BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Docket No. 2007-3-E

In the Matter of Annual Review of Base Rates for Fuel Costs for Duke Energy Carolinas, LLC	))))	**TESTIMONY OF M. ELLIOTT BATSON**

Q. PLEASE STATE YOUR NAME, ADDRESS AND POSITION WITH DUKE ENERGY.

A. My name is M. Elliott Batson and my business address is 526 South Church Street, Charlotte, North Carolina. I am Director, Coal Procurement for Duke Energy Corporation ("Duke Energy") and in that capacity I am responsible for coal procurement for Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company") as well as for Duke Energy's other regulated electric utility operating companies.

Q. STATE BRIEFLY YOUR EDUCATION, BUSINESS BACKGROUND AND PROFESSIONAL AFFILIATIONS.

A. I am a 1985 graduate of the University of South Carolina with a Bachelor of Science in Business Administration. I have been employed with Duke Energy since 1986 and have worked in the Fossil Fuel Procurement function since 1990. I am a member of the North Carolina Coal Institute.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to furnish information relating to the Company's fossil fuel purchasing practices and costs for the test period July 2006 through June 2007 and describe any changes forthcoming in the 2007 and 2008 forecast period. I will also address the limestone costs that are included in the proposed fuel factor in accordance with the recent changes to the South Carolina fuel cost recovery statute that allow for the inclusion of reagent costs.

Q. YOUR TESTIMONY INCLUDES FOUR EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes.

Q. PLEASE PROVIDE A DESCRIPTION OF THESE EXHIBITS.

A. The exhibits provide the following information:

Batson Exhibit 1 – Fossil Fuel Procurement Practices

Batson Exhibit 2 – Fossil Fuel Purchases and Consumption

Batson Exhibit 3 – Comparison of Central Appalachia Market Coal Prices to Duke Energy Carolinas Average Coal Cost for the Test Period and Projected Costs

Batson Exhibit 4 – Fossil Fuel Inventories

Q. MR. BATSON, CAN YOU PROVIDE A SUMMARY OF DUKE ENERGY CAROLINAS' FOSSIL FUEL PROCUREMENT PRACTICES?

A. Yes. The Company continues to follow the same procurement practices that it has historically followed, and a summary of those practices is set out in Batson Exhibit 1.

Q. PLEASE DISCUSS THE COMPANY'S COST OF FOSSIL FUEL FOR THE TEST PERIOD.

A. A summary of Duke Energy Carolinas' costs as well as other statistical information for each fossil fuel category for the period July 2006 through June 2007 is set forth on Batson Exhibit 2. This exhibit includes the quantities consumed, quantities purchased, and the 12-month weighted average purchase price for each fuel. Due to the fact that several components make up the total cost of coal, coal statistics are broken down to show the average freight on board ("f.o.b.") mine cost, the transportation cost, and the delivered cost per million British Thermal Units ("BTUs").

The delivered cost per ton of coal increased approximately 12% from an average of $60.07 for the prior period (July 2005 to June 2006) to an average of $67.47 for the test period (July 2006 to June 2007). This increase is due to both increasing mine and transportation costs for coal. As I have testified in prior fuel cost adjustment proceedings, the market price for coal significantly increased three to four years ago. Because Duke Energy Carolinas purchased a large percentage of its coal supply under multi-year term contract arrangements negotiated prior to coal market increases, it benefited over the last two to three years from lower priced, longer term contracts, which resulted in significantly lower average coal mine costs in 2003 through 2006 as compared to prevailing market prices. However, as the Company's older, existing coal contracts expire, they are replaced at higher market prices. As a result, the average mine price paid by Duke Energy Carolinas increased approximately 11% from $42.07 per ton of coal during the prior period to an average mine price of $46.68 per ton of coal during the test period. Batson Exhibit 3 illustrates that Duke Energy Carolinas' average coal cost during the test year and over time compares favorably to Central Appalachia coal market prices.

The average transportation rate increased approximately 16% from $17.99 per ton during the prior period to an average of $20.79 per ton during the test period. This increase is due to (1) fuel surcharges applied by the railroads as a result of increasing fuel oil prices during 2006 and early 2007, and (2) contractual escalations for freight rates paid in 2006 and 2007. Transportation costs constituted 30% of the Company's total delivered cost of coal during the test period.

These mine and transportation prices for 2006 and 2007 are consistent with the prices I projected in my testimony in Duke Energy Carolinas' last fuel adjustment proceeding and used by the Company in developing the currently approved fuel factor being billed for the October 2006 through September 2007 period.

The average oil cost for the test period decreased 2% to $1.838 per gallon compared to the previous review period ending June 2006. Average natural gas costs during the test period decreased 11% to $8.99/Mcf (per thousand cubic feet) when compared to the previous review period ending June 2006. These decreases reflect softer market conditions for buying oil and gas compared to the previous review period. Oil and natural gas combined accounted for only 3% of the Company's total fuel costs during the test period.

Q. WHAT CHANGES DO YOU SEE IN THE COMPANY'S COST OF COAL IN 2007 AND 2008?

A. June 2007 market prices for Central Appalachia coal to be delivered in 2007 and 2008 are significantly lower than prices over the last few years. Current coal prices are in the upper $40s per ton for 2008 delivery. Spot coal prices for 2007 delivery are low to mid $40s per ton. The primary reasons for the decline in prices from $50 to $60 per ton in previous years to the mid to upper $40s per ton today are (1) a reduction in demand for coal in 2006 and early 2007 primarily due to mild weather

(2) stable Central Appalachia coal production in 2006 and 2007 compared to 2005 after several years of declining production, (3) significantly improved utility coal inventories throughout the United States and (4) stable railroad delivery performance. These changes provide increased leverage for buyers as compared to previous years. It is still too soon to determine if these changes represent longer term fundamental changes to the market as coal suppliers are currently unwilling to offer contract terms longer than one to two years at these prices.

Given the success of our procurement strategy over the last few years for maintaining reliable supply at reasonable costs, the Company continues its practice of purchasing approximately 90% of its coal supply needs under term contracts for the given test period. The Company purchases a majority of its coal requirements under term contracts of one to three years in order to assure a dependable supply of coal with appropriate and consistent quality characteristics needed for coal generation. Duke Energy Carolinas currently has contracted for greater than 95% of the expected coal supply needs for 2007 and greater than 80% of its expected coal supply for 2008. All new term contract purchases will be competitively bid and negotiated in accordance with Duke Energy Carolinas' fuel purchasing practices described in Batson Exhibit 1.

Based upon the prices for existing coal purchase commitments and the current projected market prices for coal requirements in 2007 and 2008 that have not yet been purchased, it appears that the Company's average cost of coal will remain in the mid $40s per ton for the July 2007 through September 2008 forecast period. This average cost of coal projected is consistent with the projected market price for

Central Appalachia coal as shown on Batson Exhibit 3.

I testified in prior fuel cost adjustment proceedings regarding the purchase of synthetic fuel ("synfuel") from facilities located at Duke Energy Carolinas' Belews Creek and Marshall Steam Stations during 2003 through 2005. However, due to factors which impacted the availability of the federal tax credits that these synthetic fuel producers have historically received, these synfuel facilities ceased operations in the spring of 2006 and did not restart until the fall of 2006. The Company will continue to purchase synfuel from these facilities in 2007 as long as they remain operational, which could generate approximately \$8 to \$9 million in savings in 2007. The federal tax credit provision expires at the end of 2007, at which time these synfuel facilitates are expected to permanently cease operations.

Q. WHAT CHANGES IN TRANSPORTATION COSTS DO YOU EXPECT IN 2007 AND 2008?

Duke Energy Carolinas maintains multi-year rail contract arrangements with the Norfolk Southern Railway Company ("NS") and CSX Transportation ("CSX") for delivery of coal. In late 2006 and early 2007, Duke Energy Carolinas acquired 1,260 private rail cars for use on the CSX system. These private rail cars are leased under long term arrangements and lease costs are off-set through a reduction of base transportation rates contained in the Company's existing rail agreement with CSX. Use of private rail cars provides Duke Energy Carolinas with enhanced rail delivery performance, more efficient rail car utilization and improves our ability to source coal from more distant coal basins. Some of these rail cars are currently being used to source coal from the Northern Appalachia coal region providing Duke Energy

Carolinas with increased sourcing options. Although rail rates from the Northern Appalachia region are higher than rates from the Central Appalachia region due to a greater distance from the Carolinas, the coal is competitive on a delivered cost basis considering its lower mine cost.

The Company is not aware of any significant changes in transportation costs forthcoming in 2007 and 2008 as compared to 2006 with the exception of: (1) fuel surcharges are tied to the price per barrel of oil and could be volatile if oil prices do not remain stable, and (2) rail contract rates increase for inflationary factors pursuant to the terms and conditions of the contracts. The future activities of the railroads and the Surface Transportation Board will continue to impact the Company's level of service and cost of rail transportation. As such, the Company supports legislative and regulatory efforts to promote competition as well as to ensure reasonable rates in the railroad industry.

Q. WHAT IS THE COMPANY'S VIEW OF THE LONGER TERM MARKET DRIVERS FOR ITS COAL SUPPLY SOURCES?

A. Duke Energy Carolinas' steam stations are designed to operate using a typical Central Appalachia coal with the following basic approximate characteristics: 12,000 BTU, 12% ash and 1% sulfur content. Due to operational issues and transportation costs that affect the delivered cost of coal, the Company expects to continue to purchase the majority of its coal supply from the Central Appalachia coal supply region.

Although coal prices are lower now than compared to any point since early 2004, this region has seen significant increases in market prices since the early

2000s. Primary reasons include increasing domestic and international demand for coal over the last several years, a limited production response to this increased demand especially in Central Appalachia, increasing mining operating costs, high natural gas prices and transportation and coal quality complexities associated with alternative coal sources. Central Appalachian coal production declined for several years until 2006 and 2007 when production remained relatively flat compared to 2005. This limited production response is attributable to stringent environmental regulations and lengthy permitting requirements, and decreasing mining productivity due to the necessity of mining in more remote coal seams and under more difficult conditions as the coal reserve base depletes. Mining operating costs continue to have upward pressure due to high petroleum and steel costs, high labor costs, declining mining productivity, and a greater focus on safety as a result of several mine accidents and fatalities in 2006. Several publicly traded coal companies have reported average mining costs for Central Appalachia in the low to mid $40s per ton in 2006 and first quarter 2007, which has led coal producers to exercise production discipline as a result of declining operating margins. Most consultant forecasts indicate a gradual decline in Central Appalachia coal production over the next several years as the coal reserve base depletes and the higher costs for mining in Central Appalachia compared to other coal supply basins. Although natural gas prices have declined in the past year, they still create a high "ceiling" rate for coal prices before fuel switching since there is no competing generation between coal and natural gas. As coal consumers seek alternative coal sources, options are limited due to transportation complexities associated with moving coal over new, often longer and more expensive routes and to coal quality differences and the challenges different coal qualities bring to coal plant handling, operations and environmental compliance. These market fundamentals appear strong and are likely to cause upward pressure on market conditions and prices over the long term.

Q. GIVEN THESE MARKET FUNDAMENTALS, WHAT STEPS IS DUKE ENERGY CAROLINAS TAKING TO CONTROL ITS COAL COSTS?

A. Current Central Appalachia coal prices may be short lived given that market fundamentals appear to indicate continued upward pressure on coal prices. As a result of these market fundamentals and the projected decline in supply of Central Appalachia coal over the long term, it is important for Duke Energy Carolinas to pursue initiatives that will limit exposure to regional coal market price increases and help control and stabilize coal costs in general. Duke Energy Carolinas continues to take action to enhance a comprehensive coal procurement strategy that reduces the risk of extreme volatility in average coal costs. Aspects of this strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations such that the Company is not faced with price changes for a significant percentage of purchases at any one time, pursuing contract extension options that provide flexibility to extend terms within some price collar and developing a diverse coal supply portfolio from different coal supply regions as they become feasible and economical.

The Company is continuing its efforts to develop the ability to burn non-Central Appalachia and non-traditional Central Appalachia coal, primarily through coal blending at certain of its facilities, in order to take advantage of market opportunities to reduce coal costs as they come about. Duke Energy Carolinas, which typically issues two or three RFPs a year addressing term purchases, will continue to issue future RFPs that address coal supply from throughout the United States and international sources. The Company will continue to evaluate operational plant issues associated with non-Central Appalachia and non-traditional Central Appalachia coal as well as working closely with the appropriate railroads to develop the needed infrastructure to deliver this coal. This approach will analyze current and future opportunities and provide on-going flexibility to take advantage of different purchase opportunities in changing domestic and international market conditions.

Q. WHAT STEPS HAS DUKE ENERGY CAROLINAS TAKEN TO IMPLEMENT THIS STRATEGY?

A. Duke Energy Carolinas continues to maintain a comprehensive coal procurement strategy. This comprehensive strategy has been demonstrated over the last several years by limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace. Duke Energy Carolinas has also demonstrated the ability to diversify a potion of its coal supply portfolio as economics warrant. In 2006, Duke Energy Carolinas imported almost 600,000 tons of South American coal at competitive, quality adjusted delivered cost pricing. Due to the declining market prices for Central Appalachia coal in 2006 and 2007 and continuing strong market conditions for coal into Europe, this volume will significantly decline in 2007 as less costly supply options now exist. The Company continues to closely monitor the market conditions for future opportunities to re-establish this coal supply into the Carolinas as economics warrant.

Flue gas desulfurization equipment – "scrubbers" – installed at the Marshall Steam Station became operational in the second half of 2006 and first half of 2007. In 2006, Duke Energy Carolinas contracted for approximately 200,000 tons of high sulfur Northern Appalachia coal and will receive approximately 1,000,000 tons in 2007 and potentially up to 1,500,000 tons in 2008. This higher sulfur coal will be blended and consumed at the Marshall Steam Station. Additional volumes of higher sulfur coal from several Eastern coal supply regions will be evaluated as future scrubbers become operational at other plants across the Carolinas. The Allen and Buck steam stations continue to blend and consume large quantities of a low btu / high ash product that results in several million dollars of coal savings annually compared to a typical coal product. Duke Energy Carolinas is currently evaluating the economics and operational issues for a test burn of Powder River Basin coal originating from Wyoming. This coal will be blended with a traditional Central Appalachian coal at the power plant. These new non-Central Appalachia and non-traditional Central Appalachia coals demonstrate an ability to pursue new and different coal qualities in an effort to reduce coal costs. This market, operational and capital cost evaluation essentially evaluates the use of these non-Central Appalachia and non-traditional coals on a total cost basis.

Q. PLEASE EXPLAIN THE COMPANY'S FUEL INVENTORY POSITIONS.

A. Batson Exhibit 4 shows inventories for coal and oil at the beginning and end of this reporting period. Coal inventories increased from 2,610,483 tons as of June 30, 2006, to 3,665,381 tons as of June 30, 2007. This increase is primarily due to strong railroad delivery performance and current spot prices that are significantly below calendar 2008 market prices. Therefore, Duke Energy Carolinas is buying spot coal at these lower prices and holding it for future use which results in lower overall costs for 2008. The increase brings the Company's current actual level of coal inventory above its projected target level; however, inventories are projected to be reduced over the next 12 to 18 months closer to target levels. As part of this effort, Duke Energy Carolinas expects to maintain appropriate inventory to support consumption requirements and will continue to closely monitor coal supplier and railroad performance.

Oil inventories as of June 30, 2007, remained approximately the same as the June 30, 2006, ending inventory.

Q. WITNESS ROEBEL DISCUSSES THE COMPANY'S ENVIRONMENTAL CONTROLS EQUIPMENT AND THE USE OF REAGENTS IN THE OPERATION OF THE EQUIPMENT. IS THE REGULATED FUELS DEPARTMENT RESPONSIBLE FOR PROCUREMENT OF ANY OF THESE REAGENTS?

A. Yes. My department is responsible for purchasing and transportation logistics for limestone that is used in the operation of Duke Energy Carolinas' flue gas desulfurization equipment, which removes sulfur dioxide from coal plant operations. There are many similarities between limestone and coal thereby leading to the decision to group these bulk commodities within the same procurement function. Limestone, like coal, is delivered by rail and requires extensive logistics support to ensure proper delivery. The volume of limestone required varies based on the sulfur content of coal. Therefore close coordination and planning between the two commodities is required. Also, inventory management of limestone is very similar to coal requiring frequent review of limestone use, deliveries and total inventory.

Q. WHAT COSTS FOR LIMESTONE ARE INCLUDED IN THE COMPANY'S PROPOSED FUEL FACTOR UNDER THE RECENT CHANGES TO THE SOUTH CAROLINA FUEL COST RECOVERY STATUTE?

A. For the July 2007 through September 2008 period, limestone use will be limited to the Marshall and Belews Creek steam stations. Projected use at each plant is approximately 20,000 tons per month once all scrubbers are fully operational. Limestone volumes will be increasing in future years as additional scrubbers are installed. Limestone supply has been secured from a central Virginia source under a long term supply contract that was competitively bid and entered into in 2004. Additionally, a multi-year rail contract with Norfolk Southern Railway has been established for Marshall and Belews Creek steam stations. Total limestone expenses are projected to be approximately $11 million for the July 2007 through September 2008 period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Duke Energy Carolinas' Fossil Fuel Procurement Practices

The Company's fossil fuel procurement practices are summarized below.

Coal

- Near and long-term consumption forecasts are computed based on factors such as: load projections, fleet maintenance and availability schedules, coal quality and cost, environmental permit and emissions considerations, wholesale energy imports and exports.
- Station and system inventory targets are determined and designed to provide: reliability, insulation from short-term market volatility, and sensitivity to evolving coal production and transportation conditions. Inventories are monitored continuously.
- On a continuous basis, existing purchase commitments are compared with consumption and inventory requirements to ascertain additional needs.
- Qualified suppliers are invited to make proposals to satisfy any additional or future contract needs.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, quality, transportation, reliability and flexibility.
- Spot market solicitations are conducted on an ongoing basis to supplement the contract structure.
- Delivered coal volume and quality are monitored against contract commitments. Coal and freight payments are calculated based on certified scale weights and coal quality analysis meeting ASTM standards. During the test period the Company utilized both destination and origin weights and analysis.

Natural Gas

- Near and long-term consumption forecasts are generated by the same system that produces coal estimates. Gas is burned exclusively in peaking assets – combustion turbines.
- Gas is not locally inventoried, but rather scheduled and delivered via pipeline on a daily basis. Oil is burned when gas is not economically available.
- In response to annual solicitation, suppliers submit proposals to provide bundled supply service to peaking facilities. This service consists of the commodity (gas), its transportation (pipeline), storage, and balancing services.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, responsiveness, reliability, and best operational fit.

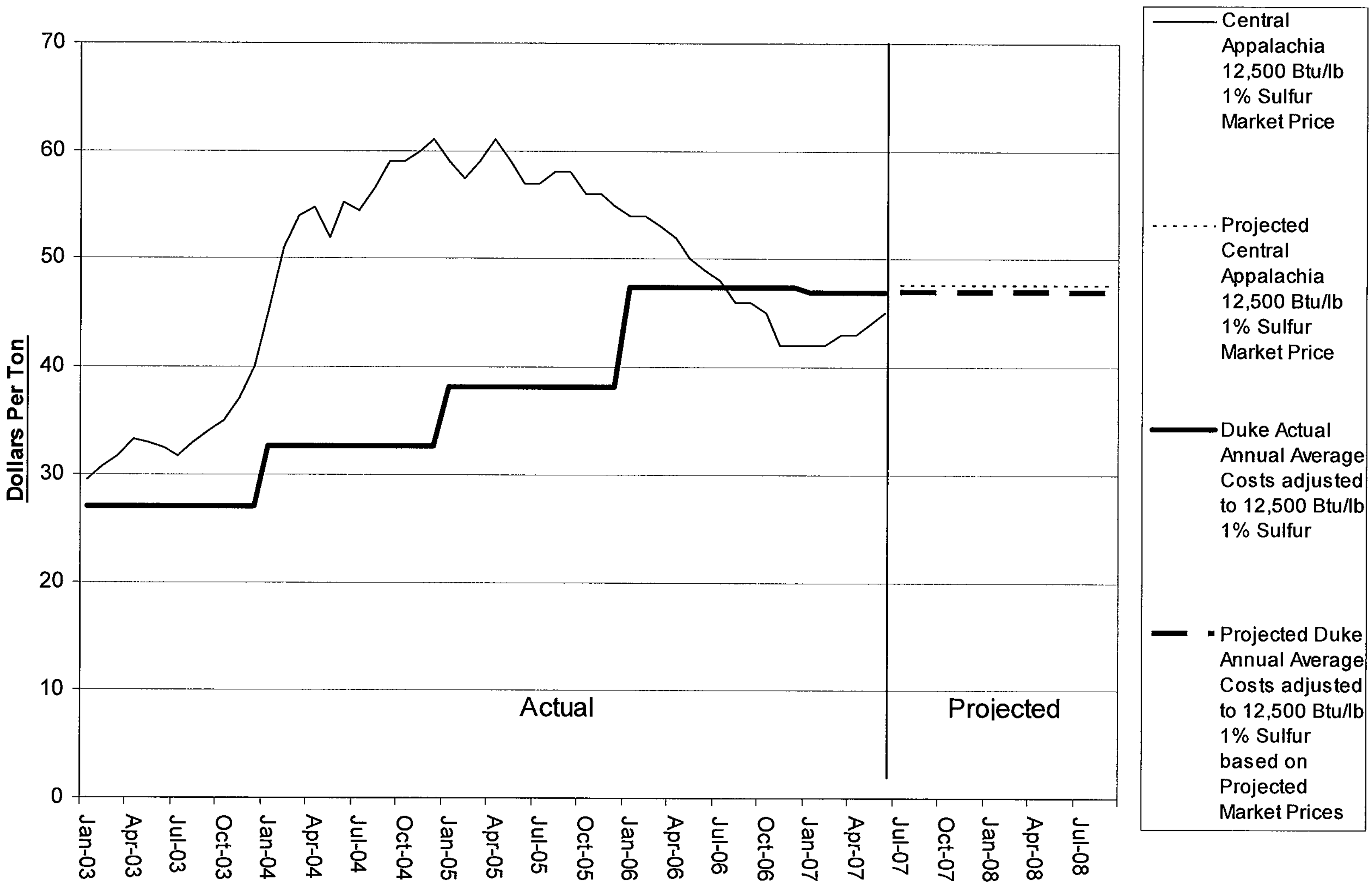
Fuel Oil

- Consumption forecasts are generated by the same system that produces coal estimates. No. 2 diesel is burned for initiation of coal combustion (light-off at steam plants) and in combustion turbines (peaking assets).
- All diesel fuel is moved via pipeline to terminals where it is then loaded on trucks for delivery into the Company's storage tanks. Because oil usage is highly variable, Duke Energy Carolinas relies on a combination of inventory and reliable suppliers who are responsive and can access multiple terminals. Diesel is replaced on an "as needed basis" as called for by station personnel with guidance from fuel procurement staff.
- Fuel orders are awarded to suppliers based on the lowest available price at the time of order. All pricing is compared and capped relative to the OPIS index.

FUEL PURCHASES AND CONSUMPTION
JULY 2006 - JUNE 2007

COAL		
	Tons Burned	18,307,216
	Tons Purchased	19,548,278
	Avg. Mine Price/Ton	$46.68
	Avg. Freight Price/Ton	$20.79
	Avg. Delivered Price/Ton	$67.47
	Avg. Delivered Price/MBTU	$2.7486
OIL		
	Gallons Consumed	10,667,970
	Gallons Purchased	12,235,889
	Avg. Price/Gallon Purchased	$1.8380
NATURAL GAS		
	Mcf. Purchased	3,341,460
	Avg. Price/Mcf.	$8.99

Comparison of Central Appalachia Market Prices to Duke Energy Carolinas Average Coal Cost



BATSON EXHIBIT 3

FUEL INVENTORIES

	06/30/06	06/30/07
COAL (TONS)	2,610,483	3,665,381
#2 OIL (GALLONS)	18,001,502	18,778,018

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Docket No. 2007-3-E

In the Matter of	)	
Annual Review of Base Rates	)	**TESTIMONY OF**
for Fuel Costs for	)	**JOHN J. ROEBEL**
Duke Energy Carolinas, LLC	)	

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CAROLINAS.

A. My name is John J. Roebel and my business address is 139 E. Fourth Street, Cincinnati, Ohio, 45202. I am employed by Duke Energy Shared Services, Inc. as Group Vice President, Engineering and Technical Services and am an officer of Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or "the Company").

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS GROUP VICE PRESIDENT, ENGINEERING AND TECHNICAL SERVICES?

A. I supervise and am responsible for the professional group that provides the technical support to the electric generating plants of the subsidiaries of Duke Energy Corporation ("Duke Energy"), including the generating plants of Duke Energy Carolinas and other generating subsidiaries of Duke Energy. This technical support includes services such as engineering, new technology evaluation, environmental health and safety, construction and project management, combustion by-product management, maintenance support, and equipment support, to enable Duke Energy Carolinas to operate a safe, reliable and efficient generation portfolio. I am also responsible for the group that provides engineering services for the electric transmission and distribution systems of Duke Energy utility subsidiaries.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a bachelor's degree in Mechanical Engineering from the University of Cincinnati Engineering College in 1980. Since that time I have taken graduate courses, primarily in business administration, from both the University of Cincinnati and from Xavier University.

I worked for The Cincinnati Gas & Electric Company ("CG&E") as a co-op student in the engineering area during undergraduate school, and became a full time employee after graduation in 1980. Since joining CG&E, and later Cinergy Services, Inc. after the merger of PSI and CG&E, I have held a number of positions of increasing responsibility in the engineering and construction management areas, including mechanical project engineer for a new coal fired unit, project manager on the conversion of CG&E's Zimmer station from nuclear to coal, and I was responsible for the design and construction of CG&E's Woodsdale Generating Station. I was promoted to my present position in April, 2006.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the performance of Duke Energy Carolinas' fossil-fueled and hydroelectric generating facilities during the period of July 1, 2006 through June 30, 2007. In addition, I discuss the status of construction and operation of environmental controls equipment and address certain reagents costs that are included in the proposed fuel factor in accordance with the recent changes to the South Carolina fuel cost recovery statute that allow for the inclusion of such costs.

Q. MR. ROEBEL, PLEASE DESCRIBE DUKE ENERGY CAROLINAS' FOSSIL AND HYDROELECTRIC GENERATION PORTFOLIO.

A. Duke Energy Carolinas' fossil/hydro generation portfolio consists of 14,188 MWs of generating capacity, made up as follows:

Coal-fired generation - 7,754 MWs

Hydroelectric - 3,168 MWs

Combustion Turbines - 3,266 MWs

(Combustion turbines can operate on natural gas or fuel oil)

This portfolio includes a diverse mix of units that allow the Company to meet the continuously changing customer load pattern in a logical and cost-effective manner. The cost and operational characteristics of each unit generally determine the type of customer load situation that the unit would be called upon to support. Base load units typically have very low operating costs but relatively high initial capital costs to install. These larger units are called upon first to support customer load requirements and thus run almost continuously. In addition to Duke Energy Carolinas' seven nuclear units, the seven largest coal fired units often operate under these base load conditions. Intermediate units are dispatched next to support customer demand, ramping up and down throughout each day to match load requirements as they change. These units take time to ramp up from a cold shut down and are best used to respond to more predictable system load patterns. This intermediate fleet is made up of thirteen coal units. During periods of highest customer demand, many of these units will also operate at maximum capacity and almost continuously along with the base load units discussed above.

Peaking units typically have higher operating costs but lower initial capital costs to install than base load or intermediate units. They have the ability to be started quickly in response to a sharp increase in customer demand, without having to operate continuously. These peaking units are called upon when customer demand is high and thus typically have lower capacity factors than the base load or intermediate units. The remaining ten small coal units as well as the entire gas/oil-fired combustion turbine fleet and entire hydroelectric fleet make up this peaking category. The Company's hydroelectric and combustion turbine units are especially good for supporting abrupt changes in load demand as their generation output can usually ramp up or down very quickly.

Witness Jones will discuss the nuclear fleet in his testimony.

Q. WHAT CHANGES TO THE FOSSIL/HYDRO PLANT CAPACITY HAVE BEEN MADE DURING THIS TEST PERIOD?

A. On November 9, 2006, Duke Energy Carolinas acquired the Rockingham combustion turbine facility from Rockingham Power, LLC, a subsidiary of Dynegy, Inc., which added 825 MW of dual gas and oil-fired peaking capacity to the Company's system. This facility is located in Rockingham County, North Carolina.

On January 4, 2007, Duke Energy Carolinas placed new combustion turbines in service at the Lee Steam Station near Pelzer, South Carolina, replacing retired combustion turbine capacity at the same site. The primary function of these combustion turbines is to provide secondary backup power to the Oconee Nuclear Station. The two new units 7C and 8C collectively add 84 MW of peaking capacity to the Company's system, while the three retired units 4C, 5C and 6C reduce this peaking capacity collectively by 90 MW. Overall, this combustion turbine replacement project reduced system capacity by 6 MW; however, the reliability of equipment in service is significantly improved.

Q. WHAT ARE THE COMPANY'S OBJECTIVES IN THE OPERATION OF ITS FOSSIL AND HYDRO GENERATION ASSETS?

A. The primary objective of Duke Energy Carolinas' Fossil/Hydro generation personnel is to safely provide reliable and cost effective electricity to our Carolinas customers. This objective is achieved though our focus in a number of key areas. Operations personnel and other station employees are well trained and execute their responsibilities to the highest standards, in accordance with procedures, guidelines and a standard operating model. We achieve compliance with all applicable environmental regulations. We maintain station equipment and systems in a cost-effective manner to ensure reliability. We take action in a timely manner to implement work plans and projects that enhance the performance of systems, equipment and personnel, consistent with providing low cost power to our customers. Equipment inspection and maintenance outages are scheduled when appropriate; are well-planned and executed with quality, with the primary purpose of preparing the plant for reliable operation until the next planned outage.

Q. PLEASE DISCUSS THE PERFORMANCE OF DUKE ENERGY CAROLINAS' FOSSIL GENERATING SYSTEM DURING THE TEST PERIOD.

A. Duke Energy Carolinas' generating system operated efficiently and reliably during the test period. Two key measures are used to evaluate the performance of generating facilities: equivalent availability factor and capacity factor. Equivalent availability factor refers to the percent of a given time period a facility was available to operate at full power if needed. Equivalent availability is not affected by the manner in which the unit is dispatched or by the system demands; however, it is impacted by planned and forced outage time. Capacity factor measures the generation a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity. Capacity factor is affected by the dispatch of the unit to serve customer needs. Given the different operating characteristics it is appropriate to evaluate these factors based on the operational categories discussed above -- base load, intermediate and peaking.

Duke Energy Carolinas' seven base load coal units achieved results of 85.9% equivalent availability factor and 77.5% capacity factor over the test period. During the peak summer season within this test period, these base load units achieved excellent results of 91.8% equivalent availability factor and 83.1% capacity factor. The Company's thirteen intermediate coal units achieved results of 87.9% equivalent availability factor and 59.5% capacity factor over the test period and performed similarly during the summer peak months at 88.4% equivalent availability and 61.1% capacity. Consistent with their load following use, mild weather and the comparatively large nuclear base load composition of the Company's generation fleet impacted the capacity factor results of these units. Duke Energy Carolinas' ten peaking coal units achieved results of 89.1% equivalent availability factor and 35.7% capacity factor and performed similarly during the summer peak months at 88.0% equivalent availability and 40.8% capacity. Overall, the coal units achieved a fleet-wide availability factor of 86.7% for the test period and 90.5% during the summer peak months. These results exceed the most recently published NERC average equivalent availability for coal plants of 84.5%. This

NERC availability average covers the period 2001-2005 and represents the performance of over 800 North American coal-fired units.

The Company's combustion turbines were available for use as needed but were required to run only infrequently due to the relatively mild weather in this time period. These factors are consistent with the intended purpose of peaking capacity. A key measure of success for the combustion turbine fleet is starting reliability. During this twelve month period, the large combustion turbines at the Lincoln, Mill Creek and Rockingham plants had 533 successful starts out of 554 requests for a 96.2% starting reliability result.

These results are indicative of solid performance and good operation and management of Duke Energy Carolinas' fossil fleet during the test period, particularly in light of the number of scheduled outage days required for environmental controls installations which I will discuss below.

Q. WHAT HAS BEEN THE HEAT RATE OF DUKE ENERGY CAROLINAS' COAL UNITS DURING THE TEST PERIOD?

A. Over this same time period, the average heat rate for the coal fleet was 9,581 BTU/kWh. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as BTUs per kilowatt-hour (BTU/kWh). A low heat rate indicates an efficient generating system that uses less heat energy from fuel to generate electrical energy. Duke Energy Carolinas has consistently been an industry leader in achieving low heat rates. In the November/December 2006 issue of *Electric Light and Power* magazine, Duke Energy Carolinas' Belews Creek Steam Station and Marshall Steam Station ranked as the country's second and third most energy efficient coal-fired generators, respectively. The Belews Creek and Marshall units provide the majority (63.9%) of coal-fired generation for Duke Energy Carolinas. In this publication, the Belews Creek Steam Station heat rate was calculated at 9,067 BTU/kWh, and the Marshall Steam Station heat rate was calculated at 9,097 BTU/kWh.

Q. PLEASE DISCUSS THE PERFORMANCE OF THE COMPANY'S HYDROELECTRIC FACILITIES DURING THE TEST PERIOD.

A. The hydroelectric fleet had outstanding operational performance during the test period with an excellent overall availability factor of 83.7%. This availability factor measurement refers to the percentage of a given time period that each hydroelectric unit was available to operate if needed. This availability measure is not affected by the manner in which the unit is dispatched, but is impacted by the amount of unit outage time. In addition to outages, the availability of hydroelectric generation is impacted by the amount of rainfall and the elevation levels of the water systems on which the facilities operate. Over the test period, these low flow conditions on the Catawba-Wateree system have restricted the amount of generation capable of being produced by the hydroelectric fleet. As part of the Federal Electric Regulatory Commission ("FERC") hydroelectric relicensing process for the Catawba – Wateree project the Company proposed a formal Low Inflow Protocol ("LIP") to be included in the final agreement among the stakeholders to be submitted to FERC; it was developed on the basis that all parties with interests in water quantity will share the responsibility to establish priorities and to conserve the limited water supply. The purpose of the LIP is to establish procedures for reductions in water use during periods of low inflow to the Catawba – Wateree Project. During the majority of the test period, the Company was operating under a voluntarily initiated Stage 1 drought condition in the Catawba – Wateree basin in accordance with the proposed LIP.

Q. MR. ROEBEL, PLEASE DISCUSS SIGNIFICANT OUTAGES OCCURRING AT DUKE ENERGY CAROLINAS FOSSIL AND HYDROELECTRIC FACILITIES DURING THE TEST PERIOD.

A. In general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize the units' availability during periods of peak demand. While most of these units had at least one small planned outage during this test period to inspect and repair critical boiler and balance of plant equipment or for the final tie-in of new environmental control equipment, eight of the thirty coal units had extended planned outages of three weeks or more. In all but one instance, the primary driver for the outage schedule was to install new environmental control equipment with the unit off-line. Allen Unit 2 is the only exception for the coal fleet, where planned air preheater and turbine valve work dictated the schedule as opposed to the environmental equipment work performed on the unit at the same time. As a result of these planned outages during the test period, all four units at Marshall now are operating with the Flue Gas Desulfurization ("FGD" or "Scrubber") technology in place for reduced sulfur dioxide ("SO_2") emissions, eight additional Selective Non-Catalytic Reduction ("SNCR") systems are operating to provide reductions to nitrogen oxide ("NO_x") emissions, and four additional peaking coal units have been outfitted with burner upgrades to further reduce NO_x emissions. The electrostatic precipitator replacement for Marshall Unit 3 was also completed during this test period, greatly improving the reliability and particulate collection efficiency of this unit.

On the hydroelectric fleet, two of the four Jocassee pumped storage units incurred significant planned outage time for runner replacements designed to increase the efficiency and capacity of the units. The Bad Creek station also completed a station-wide outage where spherical valve work and spare transformer additions were completed for the purpose of increasing station reliability. For the large combustion turbine fleet, two units at the Lincoln facility underwent regularly scheduled hot gas path inspection outages.

Q. PLEASE DISCUSS HOW THE COMPANY'S PROGRESS ON ENVIRONMENTAL CONTROLS AND COMPLIANCE PROJECTS IMPACTS THE AVAILABILITY OF THE FOSSIL FLEET.

A. As I discussed earlier, the Company continued to install pollution control equipment over the test period. This equipment is required to reduce NO_x and SO_2 emissions in accordance with federal, state and local requirements. Selective Catalytic Reduction ("SCR") or SNCR equipment is now installed and operational on sixteen coal-fired units with three additional installations in progress. Burner replacements have also been installed on other peaking coal units for enhanced NO_x performance. Duke Energy Carolinas also made significant progress on the installations of Scrubber technology in support of the SO_2 emission limits. The first four scrubbed units at Marshall were placed in service during the test period with the remaining Scrubber installations at Belews Creek, Allen and Cliffside Unit 5 in progress.

Duke Energy Carolinas minimizes the amount of scheduled outage time necessary for these environmental equipment additions when possible by performing multiple projects during a scheduled outage and performing as much construction work as possible while the units are online. However, these mandated environmental installation projects and the electrostatic precipitator replacement for Marshall Unit 3 that I discussed earlier required significantly greater planned outage days as compared to that typically experienced for the fossil fleet. In addition to the outages necessary for installation of these environmental controls, having this environmental equipment in service impacts the day-to-day operation of the fossil fleet. The SCR and Scrubber equipment itself requires power which reduces the overall output of these facilities. Retrofitting existing units to support such equipment is expected to result in balance of plant operational issues that the station personnel monitor and address as they arise.

Q. HOW DOES THIS ENVIRONMENTAL CONTROL EQUIPMENT IMPACT THE TYPES OF FUEL DUKE ENERGY CAROLINAS MAY BURN IN ITS COAL-FIRED FACILITIES?

A. The installation of the Scrubber technology on twelve of Duke Energy Carolinas' coal-fired units under the Company's compliance plan will provide the opportunity to burn higher sulfur coal at these units. Witness Batson describes the opportunities the Company has already taken to blend and burn Northern Appalachian coal at Marshall in his testimony.

Keep in mind, however, that the Company's coal-fired units were designed over thirty years ago to burn Central Appalachian coal of certain specifications.

Different boiler equipment designs and fuel blends present their own unique operational challenges as environmental controls modifications are added and the fuel supply is modified from the original design specifications. Upon resolving the environmental constraints limiting the use of higher sulfur coal through the installation of Scrubbers, Duke Energy Carolinas must assess and address a potential host of other operational constraints that may arise in connection with using non-traditional fuels. These constraints include "slagging" and "fouling" (accumulation of ash deposits on boiler surfaces), coal handling impacts and methods to manage ash basin chemistry and increased erosion. During the test period, the Company made significant investments in soot blowers at its Marshall station which should help address the slagging issues associated with burning higher sulfur coals. Duke Energy Carolinas will build upon its experience at Marshall in evaluating potential operational strategies and improvement projects to address such operational constraints to burning a more diverse combination of coals to support the Company's least-cost fuel strategy as additional Scrubbers come online.

Q. ON MAY 3, 2007, CHANGES TO THE SOUTH CAROLINA FUEL RECOVERY STATUTE BECAME EFFECTIVE WHICH AMENDED THE DEFINITION OF "FUEL COSTS" TO INCLUDE ENVIRONMENTAL REAGENTS. PLEASE DISCUSS THE USE OF REAGENTS IN CONNECTION WITH THE OPERATION OF THESE ENVIRONMENTAL EQUIPMENT ADDITIONS.

A. As discussed above, Duke Energy Carolinas is required to install and operate pollution control equipment on its coal units in order to meet various federal, state and local reduction requirements for NO_x and SO_2 emissions. The SCR technology is currently installed and operational on three coal units, and the SNCR technology is currently installed and operational on 13 units for the purpose of reducing NO_x emissions with additional installations of both technologies planned. The Scrubber technology is currently installed and operational on four units for the purpose of reducing SO_2 emissions with additional installations planned. Each of these technologies requires the presence and consumption of a reagent in order for the chemical reaction to occur that eliminates the NO_x or SO_2 emissions. The SCR technology that the Company operates uses ammonia in the presence of a catalyst for NO_x removal, the SNCR technology injects urea into the boiler for NO_x removal, and the Scrubber technology that the Company operates uses crushed limestone for SO_2 removal. Organic acid (also referred to as "DBA" or "dibasic acid") can also be used with the Scrubber technology for additional SO_2 removal.

The quantity of reagent consumed in these emission reduction processes varies depending on the generation output of the unit, the chemical constituents in the coal being burned and the level of emission reduction required. Station operators must monitor each of these parameters to ensure that the equipment is being operated in the most efficient and effective manner possible, optimizing emission reduction goals and the overall cost effectiveness of unit operations.

Q. HOW DOES THE COMPANY ENSURE THAT COSTS ASSOCIATED WITH THESE REAGENTS ARE PRUDENT AND MANAGED EFFECTIVELY?

A. The Company's objective in procurement of these environmental reagents is to provide the stations with the most effective total cost solution for operation of the pollution control equipment, understanding the technical capabilities of the equipment, assessing reagent needs over the long term, assessing the various reagent markets, and looking for leverage opportunities by combining reagent purchases with those associated with the Company's Midwest operations.

Sourcing teams have been established to accomplish these objectives for the NO_x reagents in use, currently ammonia and urea. These teams have developed action plans for the short term, including the review and refinement of reagent transportation methods and consolidation of contracts, as well as strategies for long term. Witness Batson addresses the procurement of limestone used for SO_2 removal.

Q. WHAT COSTS FOR AMMONIA, UREA AND ORGANIC ACID ARE INCLUDED IN THE COMPANY'S PROPOSED FUEL FACTOR?

A. For the period of July 1, 2007 through September 30, 2008, Duke Energy Carolinas is currently projecting to consume approximately $9.8 million worth of ammonia in operating the SCR equipment at the Belews Creek and Cliffside stations and approximately $10.1 million worth of urea in operating the SNCR equipment at the Allen, Buck, Marshall and Riverbend Stations. Additionally, it is estimated that $0.8 million worth of organic acid will be consumed in operating the Scrubber equipment at Marshall. In addition to the limestone consumption discussed by Witness Batson, the Company has included $20.7 million in estimated ammonia, urea and organic acid reagent cost in calculating its environmental component of its the proposed fuel factor.

Q. MR. ROEBEL, DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Docket No. 2007-3-E

In the Matter of	)	
Annual Review of Base Rates	)	**TESTIMONY OF**
for Fuel Costs for	)	**RONALD A. JONES**
Duke Energy Carolinas, LLC	)	

Q. PLEASE STATE YOUR NAME, ADDRESS AND POSITION.

A. My name is Ronald A. Jones. My business address is 526 South Church Street, Charlotte, North Carolina. I am Senior Vice President, Nuclear Operations for Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or "the Company").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DUKE ENERGY CAROLINAS?

A. As senior vice president of nuclear operations, I am responsible for providing direct oversight for the day-to-day safe and reliable operation of all three Duke Energy Carolinas-operated nuclear stations—Oconee, McGuire and Catawba. This includes providing direction for operations, security, safety, engineering, maintenance, radiation protection, chemistry, etc.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Virginia Polytechnic Institute and State University in Blacksburg, Virginia with a Bachelor-of-Science degree in electrical engineering. I am a member of the American Nuclear Society and the Institute of Electrical and Electronic Engineers, and a past member of the Tennessee Valley Authority and Progress Energy's Nuclear Safety Review Boards. I began my career at Duke Energy Carolinas in 1980 as an engineer at Catawba Nuclear Station. I received my senior operator license in 1987. After a series of promotions, I was named manager, maintenance engineering, in 1988; superintendent, instrument and electrical, in 1991; superintendent, operations, McGuire Nuclear Station, in 1994; station manager, Catawba Nuclear Station, in 1997; and station manager, Oconee Nuclear Station, in 2001. I was named vice president, Oconee Nuclear Station, in 2002. I was named to senior vice president of nuclear operations in January 2006.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the performance of Duke Energy Carolinas' nuclear generation fleet during the July 2006 through June 2007 test period and describe changes forthcoming in the July 2007 through September 2008 forecast period.

Q. YOUR TESTIMONY INCLUDES 3 EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision.

Q. PLEASE PROVIDE A DESCRIPTION OF THE EXHIBITS.

A. The exhibits and descriptions are as follows:

Jones Exhibit 1 -	Calculation of the nuclear capacity factor for the test period pursuant to SC Code Ann. § 58-27-865
Jones Exhibit 2 -	Nuclear outage data for the test period
Jones Exhibit 3 -	Nuclear outage data for the forecast period

Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' NUCLEAR GENERATION PORTFOLIO.

A. Duke Energy Carolinas' nuclear generation portfolio consists of approximately 5,000 MWs of generating capacity, made up as follows:

Oconee Nuclear Station - 2,538 MWs
McGuire Nuclear Station - 2,200 MWs
Catawba Nuclear Station - 282 MWs (Duke Energy Carolinas' 12.5% ownership of the Catawba Nuclear Plant)

Q. MR. JONES, PLEASE PROVIDE A GENERAL DESCRIPTION OF DUKE ENERGY CAROLINAS' NUCLEAR GENERATION ASSETS.

A. Duke Energy Carolinas' nuclear fleet consists of three generating stations with seven generation units. Oconee Nuclear Station, located in Oconee County, South Carolina, began commercial operation in 1973 and was the first nuclear station designed, built and operated by Duke Energy Carolinas. It has the distinction of being the second nuclear station in the country to have its license renewed by the Nuclear Regulatory Commission ("NRC"). The operating licenses for Oconee 1, 2, and 3, originally issued for 40 years, were renewed for an additional 20 years until 2033, 2033 and 2034, respectively. McGuire Nuclear Station, located in Mecklenburg County, North Carolina began commercial operation in 1981. Duke Energy Carolinas jointly owns the Catawba Nuclear Station, located on Lake Wylie in York County, South Carolina, with North Carolina Municipal Power Agency Number One ("NCMPA"), North Carolina Electric Membership Corporation ("NCEMC"), Piedmont Municipal Power Agency ("PMPA") and Saluda River Electric Cooperative, Inc. ("Saluda River"). In 2003, the NRC renewed the licenses for McGuire and Catawba, extending operations until 2041 (McGuire 1) and 2043 (McGuire 2, Catawba 1 and 2). In December 2006, the Company and NCEMC announced agreements to purchase Saluda River's ownership interest in unit 1 of

Catawba Nuclear Station subject to approval by various state and federal agencies. Following the planned October 2008 closing of the purchase, Duke Energy Carolinas ownership interest in the Catawba station will increase from 12.5% to 19.35% (282 MW to 437 MW). The Company's nuclear fleet supplied almost half of the power used by its customers during the test period.

Q. WHAT ARE THE COMPANY'S OBJECTIVES IN THE OPERATION OF ITS NUCLEAR GENERATION ASSETS?

A. The primary objective of Duke Energy Carolinas' nuclear generation department is to provide safe, reliable and cost effective electricity to our Carolinas customers. This objective is achieved though our focus in a number of key areas. Operations personnel and other station employees are well trained and execute their responsibilities to the highest standards, in accordance with detailed procedures. We maintain station equipment and systems reliably, and ensure timely implementation of work plans and projects that enhance the performance of systems, equipment and personnel. Station refueling outages are conducted through the precise execution of well-planned, quality work activities, which effectively ready the plant for operation until the next planned outage.

Q. MR. JONES, PLEASE DISCUSS THE PERFORMANCE OF THE COMPANY'S NUCLEAR GENERATING SYSTEM DURING THE PERIOD JULY 2006 THROUGH JUNE 2007.

A. During the test period, all three of Duke Energy Carolinas' nuclear stations were recognized by INPO for excellence in nuclear plant performance. For the eleventh consecutive year, the Electric Power Research Institute has ranked Catawba Nuclear

Station as the most thermally efficient nuclear power plant in the United States. In 2006, Catawba Unit 1 had the lowest heat rate in the country and Catawba Unit 2 came in second with heat rates of 9,534 Btu per kwh and 9,542 Btu per kwh, respectively. The Company's 2006 nuclear system total capacity factor was 90.08 percent which was the fourth highest capacity factor for a five refueling outage year. In addition, McGuire Unit 1 and Oconee Unit 2 achieved capacity factors of 103.44 percent and 99.74 percent, respectively. McGuire Unit 2 had a 513 day continuous run, the second longest run for a Duke Energy Carolinas unit.

The Company's nuclear plants operated extremely well during the test period. Jones Exhibit 1 sets forth the achieved nuclear capacity factor for the period July 2006 through June 2007 based on the criteria set forth in Section 58-27-865, Code of Laws of South Carolina. The statute states in pertinent part as follows:

> There shall be a rebuttable presumption that an electrical utility made every reasonable effort to minimize cost associated with the operation of its nuclear generation facility or system, as applicable, if the utility achieved a net capacity factor of ninety-two and one-half percent or higher during the period under review. The calculation of the net capacity factor shall exclude reasonable outage time....

As shown on Jones Exhibit 1, Duke Energy Carolinas achieved a net nuclear capacity factor, excluding reasonable outage time, of 102.70% for the current period. This capacity factor is well above the 92.5% set forth in S.C. Code § 58-27-865.

Q. PLEASE DISCUSS OUTAGES OCCURING AT THE COMPANY'S NUCLEAR FACILITIES DURING THE JULY 2006 THROUGH JUNE 20007 TEST PERIOD.

A. In general, refueling requirements, maintenance requirements, NRC operating requirements, and the complexity of operating nuclear generating units impact the availability of the Company's nuclear system. However, over the course of the years of operating the nuclear fleet the Company's nuclear performance has improved dramatically. Shorter refueling outages and improved forced outage rates have contributed to increasing the capacity factor of the nuclear fleet to consistently above 90% in recent years. Duke Energy Carolinas continues to be a leader in nuclear performance; however, the Company is not alone in its excellence. The nuclear industry as a whole has been making great strides in improving operating performance. Yet this trend of increasing capacity factors will be impacted by the refurbishment projects necessary as a result of the license renewals granted by the NRC for the Company's nuclear facilities and other projects necessary as a result of regulatory requirements by the NRC. In order for Duke Energy Carolinas and its customers to receive the benefit of continued operation of the Company's nuclear fleet for the next several decades, additional outage time over and above what Duke Energy Carolinas has experienced in recent years will be necessary to perform these projects. Likewise, as other nuclear utilities receive license renewals and begin performing the work necessary to extend the life of their facilities, we expect the industry operating performance to reflect these trends.

If an unanticipated issue is discovered while a unit is offline for a scheduled outage, the outage is extended if necessary to take the time to perform necessary maintenance or repairs prior to returning the unit to service. It is our belief that such extensions during non-peak periods result in longer continuous run times and fewer forced outages thereby reducing fuel costs in the long run. In the event that a unit is forced off line, every effort is made to safely return the unit to service as quickly as possible.

There were five refueling and maintenance outages during the test period, including two that were extended for additional work and two that were delayed due to equipment issues. The Oconee Unit 2 outage, at 33 days, was the shortest scheduled refueling in the plant's nearly 35 year history. The Oconee Unit 1 refueling outage duration was twice as long as a typical refueling outage in order for the Company to perform preplanned equipment refurbishment projects necessary due to the age of the unit. The McGuire Unit 2 refueling extension of approximately 20 days was driven by NRC regulatory requirements to modify the containment sump. This first of a kind modification is required of all United States nuclear utilities in order to address a potential sump restriction concern identified by the NRC. The Catawba Unit 1 and McGuire Unit 1 refueling outages were delayed due to equipment related issues experienced during start up. Jones Exhibit 2 shows the dates of and explanations for all outages of a week or more in duration experienced during the test period.

Q. PLEASE DISCUSS THE PLANNED OUTAGE SCHEDULE FOR THE JULY 2007 THROUGH SEPTEMBER 2008 FORECAST PERIOD.

Jones Exhibit 3 shows the dates of and explanations for forecast outages of a week or more in duration. ***BEGIN CONFIDENTIAL*** [redacted]

[redacted] ***END CONFIDENTIAL***

Q. MR. JONES, DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DUKE ENERGY CAROLINAS
SOUTH CAROLINA FUEL CLAUSE
2007 ANNUAL FUEL HEARING
NUCLEAR PLANT PERFORMANCE
CAPACITY FACTOR 7/06 - 6/07

1	Nuclear System Actual Net Generation During Test Period	54,816,623	MWH
2	Total Number of Hours During Test Period	8,760	
3	Nuclear System MDC During Test Period	6,996.0	MW
4	Reasonable Nuclear System Reductions	7,910,412	MWH
5	Nuclear System Capacity Factor $\left[\frac{1}{((2*3)-4)}\right]*100$	102.70	%

JONES EXHIBIT 1

DUKE ENERGY CAROLINAS
SOUTH CAROLINA FUEL CLAUSE
2007 ANNUAL FUEL HEARING
NUCLEAR PLANT PERFORMANCE

Nuclear Outages Lasting One Week Or More - Current Period

Unit	Date of Outage	Explanation of Outage
Oconee 1	10/07/06-12/17/06	Scheduled Refueling and Equipment Refurbishment - EOC 23; includes a 15 day extension due to modification implementation delays and a shortage of qualified resources
	02/15/07-02/23/07	Electrical Generator Protection Relays activated due to detection of a major fault on 230 KV system
Oconee 2	04/28/07-05/30/07	Scheduled Refueling - EOC 22
McGuire 1	03/10/07-05/28/07	Scheduled Refueling - EOC 18; includes a 16 day delay due to control rod drive binding as a result of debris
McGuire 2	09/16/06-11/11/06	Scheduled Refueling and Equipment Modification - EOC 17; includes a 20 day extension due to modification on containment sump screen
Catawba 1	11/11/06-12/30/06	Scheduled Refueling - EOC 16; includes a 15 day delay due to diesel generator problems

JONES EXHIBIT 2

DUKE ENERGY CAROLINAS
SOUTH CAROLINA FUEL CLAUSE
2007 ANNUAL FUEL HEARING
NUCLEAR PLANT PERFORMANCE

Nuclear Outages Lasting One Week Or More - Forecast Period

Unit	Date of Outage	Explanation of Outage

REDACTED

JONES EXHIBIT 3

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Docket No. 2007-3-E

In the Matter of Annual Review of Base Rates for Fuel Costs for Duke Energy Carolinas, LLC	))))	**TESTIMONY OF DAVID C. CULP**

Q. PLEASE STATE YOUR NAME, ADDRESS AND POSITION.

A. My name is David C. Culp. My business address is 526 South Church Street, Charlotte, North Carolina. I am Manager, Nuclear Fuel Management for Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DUKE ENERGY CAROLINAS?

A. As manager of nuclear fuel management, I am responsible for nuclear fuel purchasing/contracting, spent nuclear fuel management, nuclear fuel mechanical & thermal hydraulic design, and the Company's participation in the DOE's mixed oxide ("MOX") fuel program.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of South Carolina with a Bachelor of Science degree in Mechanical Engineering and a Master's degree in Business Administration. I began my career at Duke Energy Carolinas in 1986 as an engineer and worked in various roles including nuclear fuel assembly and control component design, fuel performance, and fuel reload engineering. I assumed the commercial responsibility for purchasing uranium, conversion services, enrichment services and fuel fabrication services in 1995. In 1999, I added spent nuclear fuel management to my responsibilities. In 2003, I was named vice president of Claiborne Energy Services – a partner in the Louisiana Energy Services venture to license, construct and operate a new uranium enrichment plant in the United States. I assumed my current role in 2005.

I currently serve as Chairman of the World Nuclear Fuel Market's Board of Governors, an organization that promotes efficiencies in the nuclear fuel markets. I have previously served as Chairman of the Ad Hoc Utilities Group (AHUG), an association that promotes free trade in nuclear fuel, and Chairman of the Nuclear Energy Institute's Utility Fuel Committee, an association aimed at improving the economics and reliability of nuclear fuel supply and use.

I am a registered professional engineer in the states of North Carolina and South Carolina.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide information regarding the Company's nuclear fuel purchasing practices and costs for the test period and describe changes forthcoming in the projected period.

Q. YOUR TESTIMONY INCLUDES 2 EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Culp Exhibit 1, Graphical Representation of the Nuclear Fuel Process and Culp Exhibit 2, Nuclear Fuels Procurement Practices.

Q. MR. CULP, PLEASE DESCRIBE THE COMPONENTS THAT MAKE UP NUCLEAR FUEL.

A. In order to prepare uranium for use in a nuclear reactor, it must be processed from an ore to a ceramic fuel pellet. This process is commonly broken into four distinct industrial stages, 1) mining and milling, 2) conversion, 3) enrichment, and 4) fabrication. This process is illustrated graphically in Culp Exhibit 1.

Uranium is usually mined by either surface (open cut) or underground mining techniques, depending on the depth of the ore deposit. The ore is then sent to a mill where it is crushed and ground-up before the uranium is extracted by leaching, the process in which either a strong acid or alkaline solution is used to dissolve the uranium. Once dried the uranium oxide (U_3O_8) concentrate, often referred to as yellowcake, is packed in drums for transport to a conversion facility. Alternatively, uranium may be mined by in situ leach (ISL) in which oxygenated groundwater is circulated through a very porous ore body to dissolve the uranium and bring it to the surface. ISL may also use slightly acid or alkaline solutions to keep the uranium in solution. The uranium is then recovered from the solution in a mill to produce U_3O_8.

After milling, the U_3O_8 must be chemically converted into uranium hexafluoride (UF_6). This intermediate stage is known as conversion, and it produces the feedstock required in the isotopic separation process.

Naturally occurring uranium primarily consists of two isotopes, 0.7% U-235 and 99.3% U-238. Most of this country's nuclear reactors (including those of the Company) require U-235 concentrations in the 3-5% range to operate a complete cycle of 18 to 24 months between refueling outages. The process of increasing the concentration of U-235 is known as enrichment. The two commercially available enrichment processes, gaseous diffusion and gas centrifuge, first heat the UF_6 to create a gas. Then, using the mass differences between the uranium isotopes, the natural uranium is separated into two gas streams, one being enriched to the desired level of U-235, known as low enriched uranium, and the other being depleted in U-235, known as tails.

Once the UF6 is enriched to the desired level, it is converted to uranium dioxide (UO_2) powder and formed into pellets. This process and subsequent steps of inserting the fuel pellets into fuel rods and bundling the rods into fuel assemblies for use in nuclear reactors is referred to as fabrication. New fuel assembly orders are planned for cycle lengths of approximately eighteen months. The length of a cycle is the duration of time between when a unit starts up after refueling and when it starts up after its next refueling.

For fuel batches recently loaded into Duke Energy Carolinas' reactors, uranium concentrates has represented approximately 30% of the total direct fuel cost. Conversion services, enrichment services, and fabrication services have represented approximately 5%, 45%, and 20%, respectively. The Company expects that the uranium concentrates component will increase its relative percentage of total direct fuel cost in the future due to the recent market price increases experienced in this sector.

Q. PLEASE PROVIDE A SUMMARY OF DUKE ENERGY CAROLINAS NUCLEAR FUEL PROCUREMENT PRACTICES.

A. Duke Energy Carolinas' nuclear fuel procurement practices involves computing near and long-term consumption forecasts, establishing target inventory levels, qualifying suppliers, requesting proposals, negotiating a portfolio of supply contracts, assessing spot market opportunities and monitoring deliveries as set forth on Culp Exhibit 2.

Q. MR. CULP, WHAT CHANGES HAVE OCCURRED IN THE UNIT COST OF THE VARIOUS STAGES OF NUCLEAR FUEL DURING THE TEST PERIOD?

A. The most prominent change occurred in the uranium concentrates sector. Spot market prices for uranium concentrates have increased nearly twenty-fold since market lows occurred in calendar year 2000. During the test period, spot market prices tripled to a record high of $136.00/lb. The impact of these increases on the Company during the test period was mitigated by contracts negotiated at lower market prices prior to the test period. The average unit cost of the Company's purchases of uranium concentrates increased from $12.51/lb in the prior reporting period to $29.51/lb in the test period - notably less than the average spot market price in the same period.

Industry consultants expect spot market prices to continue to rise in the near term as exploration, mine construction, and production gear up. As the Company's current contracts expire, they will be replaced with contracts at higher market prices. These higher prices will be reflected in future periods as fuel assemblies using such uranium are fabricated and loaded into the Company's reactors.

Spot market prices for enrichment have increased more than seventy percent since market lows experienced in calendar year 2000. One hundred percent of the Company's enrichment purchases during the test period were delivered under long term contracts negotiated prior to the test period. As such, the unit cost of enrichment purchased by Duke Energy Carolinas in the test period was comparable to that purchased in the prior reporting period. As these contracts expire, they will be replaced at higher market prices which will be reflected in future periods as fuel assemblies using such enrichment are fabricated and loaded into the Company's reactors.

Market prices for fabrication have been reasonably stable in recent years and a portion of the Company's forward requirements are covered under existing long term contracts. The unit cost for fabrication services purchased by the Company in the test period was comparable to that purchased in the prior test period.

Although the unit cost of the Company's purchases of conversion increased during the test period, these increased costs have a limited impact on the overall reported fuel expense rate given that the dollar amounts for these purchases represent a relatively minor portion of the Company's total direct fuel cost.

Q. WHAT CHANGES DO YOU SEE IN THE COMPANY'S NUCLEAR FUEL COST IN 2007 and 2008?

A. Duke Energy Carolinas does not anticipate a significant increase in nuclear fuel expense through the projected period. Because fuel is typically expensed over two to three operating cycles – roughly three to five years - Duke Energy Carolinas' nuclear fuel expense in the projected period will be determined by the cost of fuel assemblies loaded into the reactors during the test period as well as prior periods. During a refueling outage, approximately one-third of the fuel in the reactor is replaced. The costs of the fuel residing in the reactors during the test period will be predominantly based on contracts negotiated prior to the recent market price increases. As a result, fuel expense during the projected period is expected to remain in the 0.4 to 0.5 cents per kWh range over the period. As fuel with a low cost basis is discharged from the reactor and lower priced legacy contracts expire, nuclear fuel expense is expected to increase in the future.

Q. WHAT STEPS IS THE COMPANY TAKING TO PROVIDE STABILITY IN ITS NUCLEAR FUEL COSTS AND TO MITIGATE AGAINST PRICE INCREASES IN THE VARIOUS COMPONENTS OF NUCLEAR FUEL?

A. As I discussed earlier and as described in Culp Exhibit 2, Duke Energy Carolinas relies extensively on long term contracts to cover the largest portion of its forward requirements in each of the four industrial stages of the nuclear fuel cycle. By staggering long term contracts over time, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility.

The above strategy depends on the willingness of fuel suppliers to offer certain pricing mechanisms under long term contracts (e.g. fixed prices, base escalated prices, or caps on market index prices). With the recent rise in uranium spot market prices, the Company is finding that suppliers are reluctant to offer these pricing mechanisms. Instead, uranium suppliers are offering contracts with delivery prices tied to future market prices with no ceilings and relatively high floor prices.

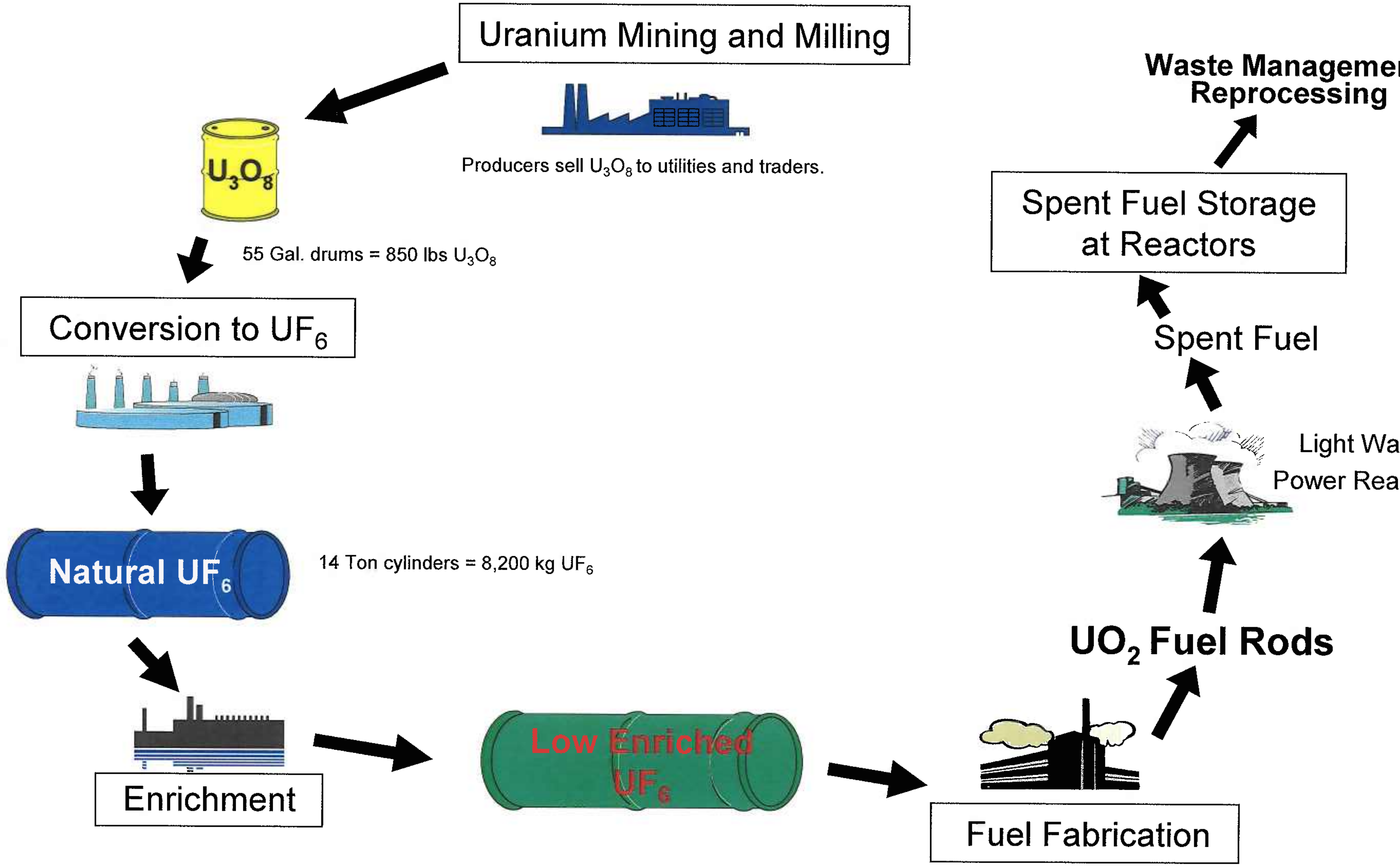
As a result of this shift, the Company has recently purchased uranium in the spot market and is holding it to meet future requirements.

Although costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a kilowatt-hour basis will likely continue to be a fraction of the kilowatt-hour cost of fossil fuel. Therefore, customers will continue to benefit from the Company's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers demands.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

The Nuclear Fuel Cycle



CULP EXHIBIT 1

CULP EXHIBIT 2

Duke Energy Carolinas Nuclear Fuel Procurement Practices

The Company's nuclear fuel procurement practices are summarized below.

- Near and long-term consumption forecasts are computed based on factors such as: nuclear system operational projections given fleet outage/maintenance schedules, adequate fuel cycle design margins to key safety licensing limitations, and economic tradeoffs between required volumes of uranium and enrichment necessary to produce the required volume of enriched uranium.
- Nuclear system inventory targets are determined and designed to provide: reliability, insulation from short-term market volatility, and sensitivity to evolving market conditions. Inventories are monitored on an ongoing basis.
- On an ongoing basis, existing purchase commitments are compared with consumption and inventory requirements to ascertain additional needs.
- Qualified suppliers are invited to make proposals to satisfy additional or future contract needs.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, reliability, flexibility and supply source diversification/portfolio security of supply.
- Spot market solicitations are conducted to supplement the contract structure as appropriate based on comparison to supplies which may be available through alternative means (such as supplies available pursuant to volume flexibilities available under long term contracts in Duke Energy Carolinas' portfolio).
- Delivered volumes of nuclear fuel products and services are monitored against contract commitments. The quality and volume of deliveries are confirmed by the delivery facility to which Duke Energy Carolinas has instructed delivery. Payments for such delivered volumes are made after Duke Energy Carolinas' receipt of such delivery facility confirmations.

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Docket No. 2007-3-E

In the Matter of	)	
Annual Review of Base Rates	)	**TESTIMONY OF**
for Fuel Costs for	)	**JANE L. McMANEUS**
Duke Energy Carolinas, LLC	)	

Q. PLEASE STATE YOUR NAME, ADDRESS AND POSITION.

A. My name is Jane L. McManeus. My business address is 526 South Church Street, Charlotte, North Carolina. I am Director, Rates for Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DUKE ENERGY CAROLINAS?

A. I am responsible for managing Duke Energy Carolina's fuel recovery processes and cost of service determination, providing guidance on compliance with regulatory conditions and codes of conduct and providing regulatory support for retail and wholesale rates.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Wake Forest University with a Bachelor of Science in Accountancy and received a Master of Business Administration degree from the McColl Graduate School of Business at Queens University of Charlotte. I am a certified public accountant licensed in the state of North Carolina and am a member of the Southeastern Electric Exchange Rates and Regulation Section and the EEI Rate and Regulatory Analysts group. I began my career with Duke Energy Carolinas (formerly Duke Power Company) in 1979 as a staff accountant and have held a variety of positions in the finance organizations. From 1994 until 1999, I served in financial planning and analysis positions within the electric transmission area of

Duke Power. I was named Director, Asset Accounting for Duke Power in 1999 and appointed to Assistant Controller in 2001. As Assistant Controller I was responsible for coordinating Duke Power's operational and strategic plans, including development of the annual budget and performing special studies. I joined the Rate Department in 2003 as Director, Rate Design and Analysis. Beginning in April 2006, I became Director, Regulatory Accounting and Filings, leading the regulatory accounting, cost of service, regulatory filings (including fuel) and revenue analysis functions for Duke Energy Carolinas. I began my current position in the Rate Department in October 2006.

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DUKE ENERGY CAROLINAS?

A. Yes. The books of account of Duke Energy Carolinas follow the uniform classification of accounts prescribed by the Federal Energy Regulatory Commission ("FERC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide the actual fuel and environmental cost data for the period July 2006 through June 2007, the test period under review in this proceeding; the projected fuel and environmental cost information for the period July 2007 through September 2008; and the Company's recommended fuel factors by customer class for billing the period October 2007 through September 2008. I will also describe how the Company proposes to implement the changes to the South Carolina fuel cost recovery statute (S.C. Code Ann. Section 58-27-865(A)), which became effective May 3, 2007, and provide for the inclusion of an environmental cost component for recovery of certain variable environmental costs.

Q. YOUR TESTIMONY INCLUDES NINE EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. Each of these exhibits was prepared at my direction and under my supervision.

Q. PLEASE PROVIDE A DESCRIPTION OF THE EXHIBITS.

A. The exhibits and descriptions are as follows:

Exhibit 1 -	Total Company Fuel Costs Detail for the Test Period
Exhibit 2 -	Coal Cost per MBTU Burned
Exhibit 3 -	Nuclear Cost per MBTU Burned
Exhibit 4 -	Source of Generation by Period
Exhibit 5 -	Test Period Fuel Costs and Revenues
Exhibit 6 -	Projected Period Fuel Costs and Revenues
Exhibit 7 -	Environmental Cost (Over)/Under Recovery by Class
Exhibit 8 -	Projected Environmental Cost Allocation by Class
Exhibit 9 -	Projected Fuel Factor by Customer Class

Q. HOW DOES DUKE ENERGY CAROLINAS MEET ITS CUSTOMERS' NEEDS FOR ELECTRICITY?

A. Duke Energy Carolinas meets its customers' needs for electricity through a combination of Company-owned generation, purchases of power from others, and customer demand-side options. Demand-side options include residential and nonresidential programs that provide credits to customers for allowing the Company to curtail their electricity usage on occasion. Each day, Duke Energy Carolinas selects the combination of Company-owned generating units and available power purchases that will reliably meet customer needs in a least cost manner. Units with the lowest overall operating costs (fuel, emission allowances and variable operations and maintenance costs, etc.) are dispatched first, with higher cost units added as load increases. Intraday adjustments are made to reflect changing conditions and purchase opportunities. Witness Jones discusses the nuclear fleet operations and witness Roebel discusses fossil and hydroelectric operations.

Additionally, the Company monitors the energy market, evaluating long-term, seasonal, monthly, weekly, daily and hourly purchase opportunities. In making these daily decisions on which resources should be used to meet customer needs, the Company may purchase energy from other suppliers, whether under long-term capacity agreements that the Company has entered into or short-term spot market purchases to ensure it selects the most cost-effective, reliable solution.

Q. PLEASE DESCRIBE THE RELATIVE COSTS OF THE VARIOUS FUELS USED BY DUKE ENERGY CAROLINAS FOR ITS GENERATING UNITS.

A. Nuclear fuel is the least costly fuel for the Company with a cost of approximately 0.4 cents/kWh. Coal costs are approximately 2.4 to 3.5 cents/kWh depending on the generating plant. While the cost of natural gas and fuel oil on a cents per kwh basis are significantly higher, the fuel expense for these fuels is small compared to total fuel expense due to the limited need to call on our combustion turbines. The fuel cost of conventional hydroelectric generation is essentially zero. The cost of pumped storage hydroelectric generation is the fuel cost of the generating unit used to pump the water to the upper reservoir. Hydroelectric operation is limited by the amount of rainfall and the amount of water that can be drawn through the units in compliance with the Company's operational licenses.

Q. HOW MUCH OF DUKE ENERGY CAROLINAS' ENERGY CONSUMED IN THE TEST PERIOD WAS GENERATED BY EACH TYPE OF GENERATING UNIT?

A. During the test period, the Company generated 87,642,930 megawatt hours ("MWHs") of electricity. The fossil units provided 54% of Duke Energy Carolinas' total generation, the nuclear units provided 45% and the hydroelectric system provided 1% (net of megawatt-hours used for pumped storage).

Q. PLEASE DESCRIBE HOW DUKE ENERGY CAROLINAS INCLUDED FUEL COSTS RELATED TO PURCHASES IN ITS FUEL EXPENSES FOR THE TEST PERIOD.

A. The definition of fuel costs related to purchased power set forth in Section 58-27-865(A) of the 1976 Code of Laws of South Carolina includes the "costs of firm generation capacity purchases, which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels" and "the total delivered cost of economy purchases of electric power." The statute further defines economy purchases as purchase "made to displace higher cost generation, at a price which is less than the purchasing utility's avoided variable costs for the generation of an equivalent amount of electric power."

In accordance with the statute, the Company used the avoided cost method to determine the fuel component of purchases of power for Duke Energy Carolinas' retail customers. Under this methodology, the Company determines the costs it would have incurred in the absence of the purchase. This cost is determined by use of a model that identifies the incremental cost of the unit that would have been dispatched in the absence of the purchase and compares that cost to the cost of the purchase. The incremental cost includes the fuel and certain variable operation and maintenance costs. The Company includes in fuel costs the lower of the cost of the energy purchase or the cost Duke Energy Carolinas would have incurred. Duke Energy Carolinas' customers thereby are ensured of receiving the benefit of purchased power.

Q. MS. MCMANEUS, PLEASE DESCRIBE HOW NUCLEAR COSTS ARE INCLUDED IN THE COMPANY'S FUEL EXPENSES.

A. The cost of each fuel assembly is determined when the fuel is loaded in the reactor. The costs include yellowcake (uranium), conversion, enrichment and fabrication. In his testimony, Witness Culp describes the components that make up nuclear fuel in greater detail. An estimate of the energy content of each fuel assembly is also made. Nuclear fuel expenses for each month are based on the energy output in units of million BTUs ("MBTUs") of each fuel assembly in the core and Department of Energy 'High Level Waste' and 'Decontamination and Decommissioning Fund' fees. A cost per MBTU is determined by dividing the cost of the assembly by its expected energy output. Each month a calculation of the MBTU output of an assembly is priced at its cost per MBTU. During the life of a fuel assembly, the expected energy output may change as a result of actual plant operations. When this occurs, changes are made in the cost per MBTU for the remaining energy output of the assembly.

Q MS. MCMANEUS, CAN YOU EXPLAIN HOW COAL COSTS ARE INCLUDED IN THE COMPANY'S FUEL EXPENSES?

A. Duke Energy Carolinas calculates coal costs charged to fuel expense on an individual plant basis. The expense charge is the product of the tons of coal conveyed to the bunkers for a generating unit during the month multiplied by the average cost of the coal. The number of tons is determined by using scales located on the conveyor belt running to the unit's coal bunkers. The average cost reflects the total cost of coal on hand as of the beginning of the month, computed using the moving average inventory method, plus the cost of coal delivered to the plant during the month. Duke Energy Carolinas determines the cost of coal based upon the invoice for the coal and the freight bill, and does not include any non-fuel cost or coal handling cost at the generating station.

Duke Energy Carolinas conducts annual physical inventories of coal piles through aerial surveys. The Company made an adjustment to book inventory for coal in December 2006 based on the results of the annual inventory.

Q. MS. MCMANEUS, WHAT DOES EXHIBIT 1 SHOW?

A. McManeus Exhibit 1 sets forth the total system actual fuel costs (as burned) that the Company incurred from July 2006 through June 2007. This exhibit also shows fuel costs by type of generation and total megawatt hours (MWH) generated during this period. The monthly fluctuations in total fuel cost during this period are primarily due to refueling and other outages at the nuclear stations, weather sensitive sales and the availability of hydroelectric generation.

Q. WHAT IS THE MAGNITUDE OF THE COMPANY'S FUEL COST COMPARED TO THE TOTAL COST OF SERVICE?

A. Fuel costs continue to be the largest cost item Duke Energy Carolinas incurs in providing electric service. For the twelve months ended May 2007, fuel and the fuel component of purchased power represented approximately 28% of the Company's total revenue. Of fuel costs, coal costs are the largest component and during the period July 2006 through June 2007 comprised approximately 86% of the costs of the Company's fuel burned.

Q. MS. MCMANEUS, WHAT CHANGES HAVE OCCURRED IN THE UNIT COST OF FUEL DURING RECENT REPORTING PERIODS?

A. McManeus Exhibits 2 and 3 graphically portray the "as burned" cost of coal and nuclear fuel respectively in cents per MBTU for the twelve month periods ending January 2005 through June 2007. As McManeus Exhibit 2 shows, coal costs increased during the period as testified to by Witness Batson. McManeus Exhibit 3 shows that nuclear fuel costs have been relatively stable over the same period. Witness Culp discusses changes in the cost of the various components of nuclear fuel in his testimony. The costs incurred by Duke Energy Carolinas for the other fossil fuels used by the Company, natural gas and fuel oil, are a very small percentage of the total fuel costs. The costs incurred during the test period for these fuels were approximately $48 million, or 3% of the Company's total fuel expense for the year.

Duke Energy Carolinas expects its composite cost of fuel to increase. As testified to by Witness Batson, the market price of coal has come down slightly in the last few years; however, the Company's cost of coal, which is more than seven times the cost of nuclear fuel, has increased over the past several years and continues to increase as older below-market contracts expire. The Company expects that future KWH growth will be met primarily from the Company's coal generating units. In addition, as discussed in greater detail by Witness Culp in his testimony, the market price of two of the components of nuclear fuel has begun to increase.

Q. WHAT DOES MCMANEUS EXHIBIT 4 SHOW?

A. McManeus Exhibit 4 graphically shows generation by type for the current and projected periods as well as three prior periods. As the Exhibit demonstrates, nuclear and fossil fuel account for nearly 100% of the Company's total generation.

Q. MS. MCMANEUS, DO YOU BELIEVE THE COMPANY'S ACTUAL FUEL COSTS INCURRED DURING THE PERIOD JULY 2006 THROUGH JUNE 2007 WERE REASONABLE?

A. Yes. I believe the costs are reasonable and that Duke Energy Carolinas has demonstrated that it meets the criteria set forth in Section 58-27-865(F) of the Code of Laws of South Carolina. These costs also reflect the Company's continuing efforts to maintain reliable service and an economical generation mix, thereby minimizing the total cost of providing service to our South Carolina retail customers.

Q. HOW DID THE COMPANY CALCULATE ITS FUEL COST RECOVERY DURING THE JULY, 2006 THROUGH SEPTEMBER, 2007 TIME PERIOD?

A. McManeus Exhibit 5 shows the actual fuel costs incurred for the period July 2006 through June 2007 and the estimated fuel costs for July 2007 through September 2007. This exhibit compares the fuel costs incurred with the revenues collected applying the applicable fuel cost component of 1.7760¢/KWH for the period October 2006 through April 2007. This factor includes a decrement for sulfur dioxide ("SO_2") emission allowance costs. The decrement results from the assignment of SO_2 emission allowance costs to intersystem sales. For the period May 2007 through September 2008, after the effective date of the changes to Section 58-27-865(A), this decrement is included in the calculation of the recovery of environmental costs shown in McManeus Exhibit 7.

Q. WHAT IS THE BASIS FOR ESTIMATING FUEL COSTS AS SHOWN ON MCMANEUS EXHIBITS 5 AND 6?

A. Duke Energy Carolinas developed the projections shown on McManeus Exhibits 5 and 6 based on the latest information available to the Company. The projected kWh sales are from the Company's spring 2007 sales forecast. Projected nuclear generation reflects planned outages, which include refueling outages at 6 units including one that extends beyond the forecast period. The projection of fuel costs are based on a 97% capacity factor for the nuclear units while they are running. The Company's most recent nuclear fuel cost estimate was used to determine projected nuclear fuel expense. Estimated hydroelectric generation for the period is based on median generation for the period 1976 - 2006. The Company estimates fuel costs of energy purchases based on historical purchase quantities and price. Oil and gas fuel costs and generation are based on a three year average. The Company assumes that the remainder of the customers' energy needs are served from coal-fired units. The projected price for coal contracts is based on the price of coal contracts that will be in place during the projection period along with the current market price for coal needs beyond the currently contracted amounts.

Q. HOW DO INTERSYSTEM SALES OF POWER AFFECT THE CALCULATION OF FUEL COSTS INCURRED AND THE PROJECTED FUEL FACTOR FOR SOUTH CAROLINA RETAIL CUSTOMERS?

A. The test period fuel costs incurred are calculated by subtracting the fuel costs associated with non-firm intersystem sales from the total system burned fuel cost. To determine the fuel costs associated with these intersystem sales, Duke Energy Carolinas uses a post dispatch model to stack the sources of generation used in each hour from least to highest total cost, and in order to hold retail customers harmless, typically assigns the highest cost generating units on an incremental basis to non-firm intersystem sales of power. The projected fuel factor is set based on an assumed amount and cost of intersystem sales. The amount of non-firm intersystem sales for the projected fuel factor is assumed to be the same as for the test year. However, the costs of projected sales are adjusted from the test year costs by the same percentage change as between the test year and projected period cost per kWh of coal since higher priced fossil generation is typically assigned to intersystem sales.

Q. WHAT DOES THE COMPANY ANTICIPATE ITS FUEL RECOVERY POSITION WILL BE AS OF SEPTEMBER 30, 2007?

A. Duke Energy Carolinas estimates that by the end of the current billing period (September 30, 2007), the Company will be over-recovered in South Carolina by approximately \$6,116,000, excluding under-recovery of environmental costs from May 3, 2007 to September 30, 2007, which I discuss below.

Q. MS. MCMANEUS, WHAT IS THE FUEL COST COMPONENT OF THE FUEL FACTORS THE COMPANY PROPOSES FOR THE BILLING PERIOD OCTOBER 2007 THROUGH SEPTEMBER 2008?

A. McManeus Exhibit 6 sets forth projected fuel costs for the period October 2007 through September 2008. As shown on line 7, the fuel cost component estimated for recovery during this period is 1.7739¢/KWH. After adjusting for the cumulative over-recovery, the adjusted fuel cost component is 1.7457¢/KWH. Therefore, each of the three fuel factors proposed by the Company for Commission approval include fuel cost component of 1.7457¢/KWH.

Q. PLEASE DESCRIBE THE CHANGES TO THE SOUTH CAROLINA FUEL COST RECOVERY STATUTE TO ADD THE RECOVERY OF CERTAIN VARIABLE ENVIRONMENTAL COSTS.

A. The Base Load Review Act, which became law on May 3, 2007, amended the definition of "fuel cost" in Section 58-27-865(A)(1) to add certain variable environmental costs as follows:

> "Fuel cost" shall also include the following variable environmental costs: (a) the cost of ammonia, lime, limestone, urea, dibasic acid, and catalysts consumed in reducing or treating emissions, and (b) the cost of emission allowances, as used, including allowance for SO2, NOx, mercury and particulates.

The statute further requires the utility to develop a separate environmental component for the recovery of these costs in accordance with the following:

> All variable environmental costs included in fuel costs shall be recovered from each class of customers as a separate environmental component of the overall fuel factor. The specific environmental component for each class of customers shall be determined by allocating such variable environmental costs among customer classes based on the utility's South Carolina firm peak demand data from the prior year. Fuel costs must be reduced by the net proceeds of any sales of emission allowances by the utility.

Q. HOW DOES DUKE ENERGY CAROLINAS PROPOSE TO IMPLEMENT THESE CHANGES?

A. The Company proposes to calculate an environmental component for each of the Residential, General Service/Lighting and Industrial customer classes based upon the (1) over or under recovery of actual costs incurred for emission allowances and reagent costs permitted under that statute ("environmental costs") for the period May 4, 2007 through June 30, 2007, (2) estimated over or under recovery of environmental costs for the period July 2007 through September 2007, and (3) projected environmental costs for the period October 2007 through September 2008. The over/under recovery of environmental costs incurred and projected environmental costs are then allocated among the three customer classes based upon firm peak load. The resulting allocated costs are converted to the environmental component for each class expressed in cents per KWH. Each environmental component is then added to the fuel component proposed above resulting in a total fuel factor for each class.

Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINED THE "FIRM PEAK DEMAND" FOR EACH CUSTOMER CLASS AND DEVELOPED THE ALLOCATION FACTORS FOR ENVIRONMENTAL COSTS.

A. We began with the demands of South Carolina retail customers by customer class at the time of Duke Energy Carolinas' 2006 summer peak. We then subtracted the amount of class demand for each customer class that is subject to interruption under the Company's approved demand-response programs in order to determine the firm demand. The firm demand for each class was then converted to a percentage of the total firm demand. This calculation is set forth on McManeus Exhibits 7 and 8. These percentages were used to allocate the environmental costs between the Residential, General Service/Lighting and Industrial customer classes.

Q. HOW DID THE COMPANY CALCULATE ITS ENVIRONMENTAL COST RECOVERY DURING THE MAY 3, 2006 THROUGH SEPTEMBER 30, 2007 TIME PERIOD?

A. McManeus Exhibit 7 shows the actual environmental costs incurred for the period May 3, 2006 through June 30, 2007 and the estimated environmental costs for July 1, 2007 through September 30, 2007. Prior to the passage of the Base Load Review Act, Section 58-27-865(A) allowed for the recovery of SO_2 emission allowance costs. Therefore, the currently approved fuel factor includes an environmental component which must be subtracted from the overall current fuel factor and compared to the actual and estimated environmental costs incurred as calculated under the amended statute.

As described above, the Company subtracts fuel costs, including SO_2 emission allowance costs, associated with non-firm intersystem sales from fuel expense in order to derive retail fuel costs. The Company uses replacement costs to determine such allowance costs. As a result of the market price of SO_2 emission allowances in the prior period, the allowance costs assigned to intersystem sales resulted in a credit to South Carolina retail fuel costs. Therefore, McManeus Exhibit 7 compares the environmental costs incurred with the revenues collected applying the applicable emission allowance decrement rate of 0.0427 ¢/KWH that was contained within the current fuel factor of 1.7760¢/KWH for the period May 2007 through September 2007.

Q. WHAT IS THE BASIS FOR ESTIMATING ENVIRONMENTAL COSTS AS SHOWN ON MCMANEUS EXHIBITS 7 AND 8?

A. As discussed by witnesses Roebel and Batson, the projected environmental costs are based upon the most current forecasts produced by appropriate departments within the Company. The Company estimates emission allowance expense and emission allowance expense recovered in non-firm intersystem sales based on actual data. Any gains on sales of emission allowances are based upon current forecasts.

Q. MS. MCMANEUS, WHAT ARE THE ENVIRONMENTAL COST COMPONENTS THE COMPANY PROPOSES FOR THE BILLING PERIOD OCTOBER 2007 THROUGH SEPTEMBER 2008?

A. McManeus Exhibit 8 sets forth projected environmental costs for the period October 2007 through September 2008. As shown on McManeus Exhibit 8, the proposed environmental cost components for recovery during this period are 0.0368¢/KWH for Residential customers, 0.0291¢/KWH for General Service/Lighting customers and 0.0181¢/KWH for Industrial customers.

Q. WHAT IS THE COMBINED COST OF FUEL THE COMPANY PROJECTS FOR RECOVERY DURING THE PERIOD OCTOBER 2007 THROUGH SEPTEMBER 2008?

A. As shown in McManeus Exhibit 9, after adjusting for the environmental under-recovery and adding in the fuel cost from line 12 of McManeus Exhibit 6, the combined fuel factors estimated for recovery during this period are 1.8215¢/KWH for Residential customers, 1.8057¢/KWH for General Service/Lighting customers and 1.7829¢/KWH for Industrial customers. The Company seeks Commission approval for these proposed combined fuel factors. Based on our estimate, the proposed combined fuel factors would result in the Company being neither under- or over-recovered in its fuel costs, including environmental costs, at the end of the billing period in September 2008.

Q. MS. MCMANEUS, DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

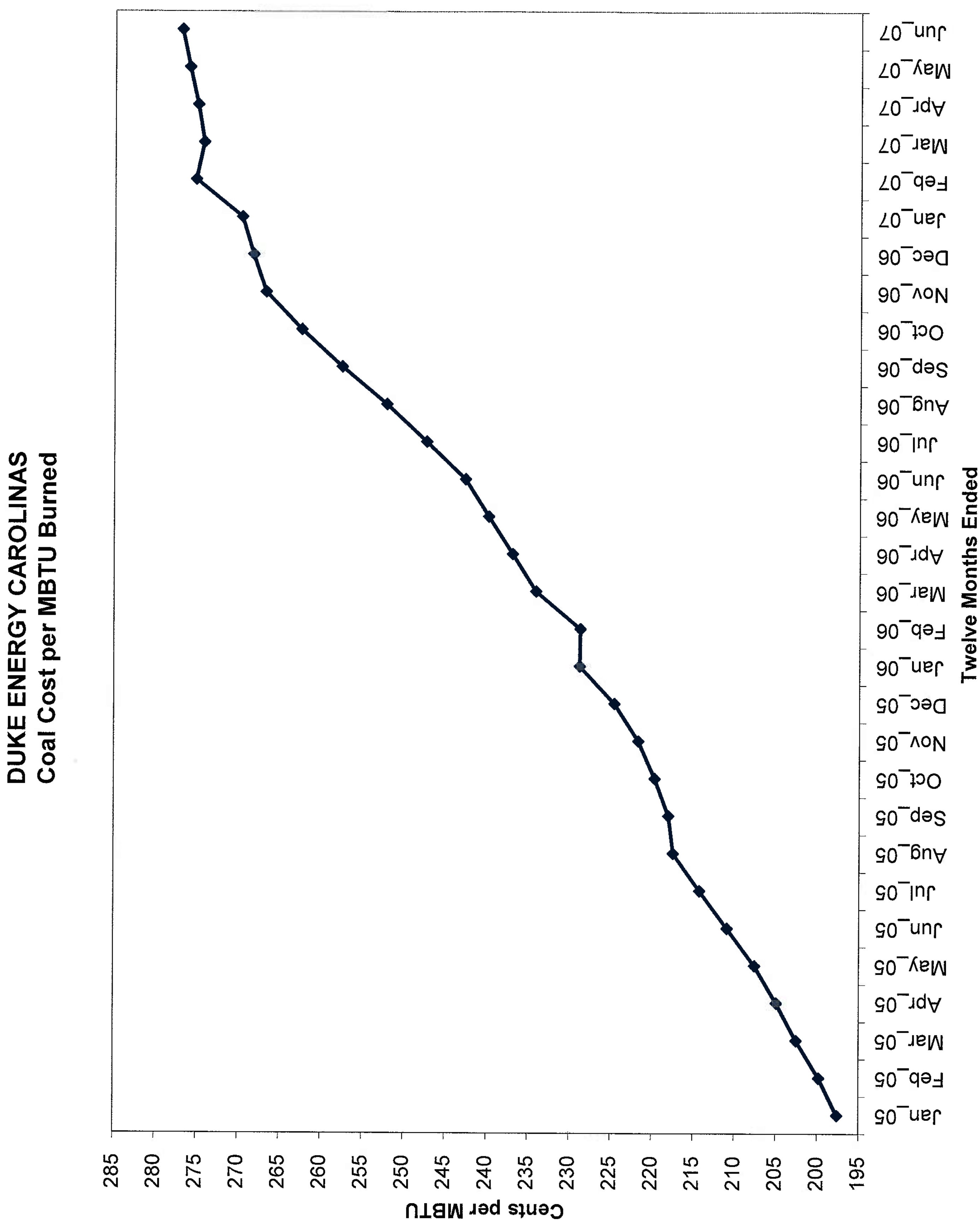
DUKE ENERGY CAROLINAS
SOUTH CAROLINA FUEL CLAUSE
2007 ANNUAL FUEL HEARING
TOTAL COMPANY FUEL COST
$000

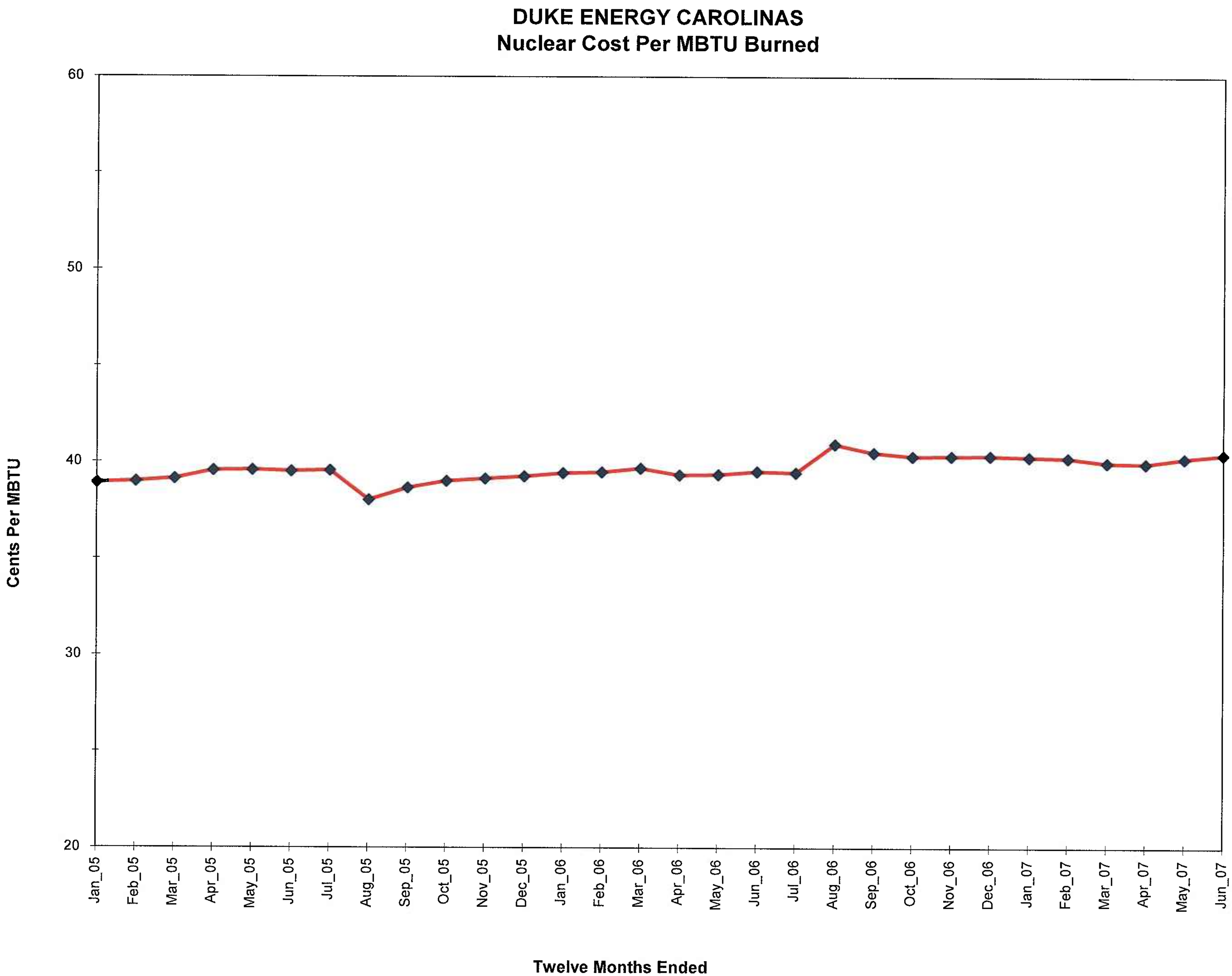
Line No.	Description	Mo. Avg. 12Mo. 6/06	July 2006	Aug. 2006	Sept. 2006	Oct. 2006	Nov. 2006	Dec. 2006	Jan. 2007	Feb. 2007	March 2007	April 2007	May 2007	June 2007	Mo. Avg. 12Mo. 6/07
1	Coal	$88,386	$119,008	$126,066	$89,668	$98,882	$97,748	$91,756	$90,832	$113,420	$96,502	$93,663	$113,663	$109,650	$103,405
2	Emission Allowance Exp.*	972	1,280	1,351	987	1,016	895	926	853	1,482	1,499	1,915	215	0	1,035
3	Oil	1,378	1,530	989	1,714	1,424	1,647	1,402	2,762	1,860	1,265	1,525	985	1,079	1,515
4	Gas	971	7,306	10,189	3,584	1,209	1,008	626	1,140	510	90	240	1,451	2,700	2,504
5	Nuclear	13,800	15,011	14,774	13,117	10,694	11,470	14,055	15,710	13,046	13,025	11,426	11,133	16,051	13,293
6	Total	$105,507	$144,135	$153,369	$109,070	$113,225	$112,768	$108,765	$111,297	$130,318	$112,381	$108,769	$127,447	$129,480	$121,752
7	MWH Gen.	7,293,793	8,216,338	8,417,575	6,583,835	6,096,278	6,250,733	7,214,106	7,383,627	7,487,177	6,947,661	6,378,672	6,755,928	7,817,690	7,129,135

*Effective May 3, 2007, changes in SC law (Section 58-27-865), allow for environmental costs incurred for reducing or treating emissions, to be included in fuel costs used in the fuel factor calculation.
See Exhibits 7 and 8 for separate environmental cost calculations.

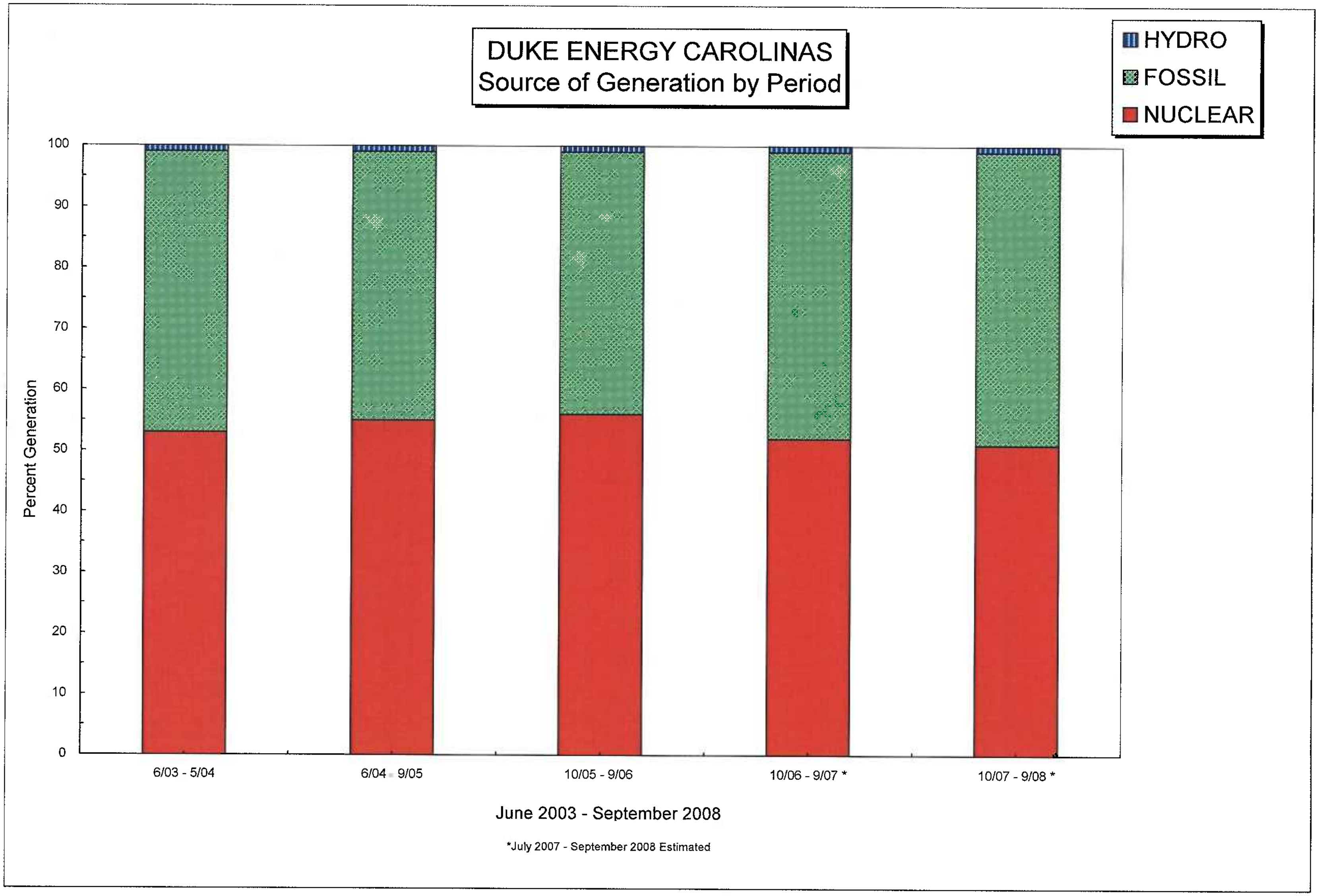
McManeus Exhibit 1

McManeus Exhibit 2





McManeus Exhibit 3



McManeus Exhibit 4

DUKE ENERGY CAROLINAS
SOUTH CAROLINA FUEL CLAUSE
2007 ANNUAL FUEL HEARING
CURRENT PERIOD FUEL COSTS INCURRED
$000

Line No.	Item	July 2006	Aug. 2006	Sept. 2006	Oct. 2006	Nov. 2006	Dec. 2006	Jan. 2007	Feb. 2007	March 2007	April 2007	May 2007*	June 2007	Estimated July 2007	Estimated Aug. 2007	Estimated Sept. 2007
1	Fossil Fuel	$127,844	$137,245	$94,966	$101,515	$100,403	$93,784	$94,734	$115,790	$97,857	$95,428	$116,099	$113,429	$133,742	$135,566	$107,288
2	Emission Allowance Exp.	1,280	1,351	987	1,016	895	926	853	1,482	1,499	1,915	21				
3	Nuclear Fuel	15,011	14,774	13,116	10,694	11,470	14,055	15,710	13,046	13,025	11,426	11,133	16,051	16,155	16,155	15,447
4	Fuel In Purchases	11,202	14,406	5,110	8,170	14,911	8,499	1,232	3,330	4,830	3,103	6,512	4,369	4,955	4,955	4,955
5	Fuel In Intersystem Sales	9,602	7,684	9,683	6,499	5,307	6,853	16,634	28,041	25,900	19,107	4,146	11,987	13,821	13,821	13,821
6	Total Costs	$145,735	$160,092	$104,496	$114,896	$122,372	$110,411	$95,895	$105,607	$91,311	$92,765	$129,619	$121,862	$141,031	$142,855	$113,869
7	MWH Sales	7,319,977	7,794,893	7,380,471	5,971,704	6,037,432	6,264,805	6,521,026	6,901,194	6,085,837	6,233,642	6,233,986	6,822,510	7,435,269	7,823,752	7,478,860
8	Fuel Cost ¢/KWH	1.9909	2.0538	1.4158	1.9240	2.0269	1.7624	1.4706	1.5303	1.5004	1.4881	2.0792	1.7862	1.8968	1.8259	1.5225
9	¢/KWH Billed	1.5802	1.5802	1.5802	1.7760	1.7760	1.7760	1.7760	1.7760	1.7760	1.7760	1.8146	1.8187	1.8187	1.8187	1.8187
10	SC Retail MWH Sales	2,038,725	2,169,427	2,017,839	1,647,460	1,671,874	1,705,410	1,795,657	1,894,719	1,614,666	1,727,296	1,647,441	1,879,747	2,041,993	2,161,977	2,064,824
11	$ (Over) Under	$8,373	$10,274	($3,317)	$2,438	$4,195	($232)	($5,485)	($4,655)	($4,450)	($4,973)	$4,359	($611)	$1,595	$156	($6,116)
12	Prior Period (Over) Under	($10,861)														
13	Economic Purchase Adj. per Docket 2006-3-E			$3,877												
14	DT Decrement Adj (Jan.) and Correction (March)			-				($867)		($2)						
15	Cumulative (Over) Under	($2,488)	$7,786	$8,346	$10,784	$14,979	$14,747	$8,395	$3,740	($712)	($5,685)	($1,326)	($1,937)	($342)	($186)	($6,302)

*Effective May 3, 2007, changes in SC law (Section 58-27-865), allow for environmental costs incurred for reducing or treating emissions, to be included in fuel costs used in the fuel factor calculation.
See Exhibits 7 and 8 for separate environmental cost calculations.

McManeus Exhibit 5

DUKE ENERGY CAROLINAS
SOUTH CAROLINA FUEL CLAUSE
2007 ANNUAL FUEL HEARING
PROJECTED FUEL COST 10/07 - 9/08
$000

Line No.	Item	Oct. 2007	Nov. 2007	Dec. 2007	Jan. 2008	Feb. 2008	March 2008	April 2008	May 2008	June 2008	July 2008	Aug. 2008	Sept. 2008	Total
1	Fossil Fuel	$93,720	$105,326	$116,443	$110,748	$96,042	$109,246	$102,943	$105,603	$120,892	$137,061	$138,733	$124,648	$1,361,403
2	Nuclear Fuel	15,412	12,958	14,064	17,216	16,163	13,713	13,399	15,516	16,348	17,216	17,216	13,786	183,007
3	Fuel In Purchases	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955	4,955	59,461
4	Fuel In Intersystem Sales	13,821	13,821	13,821	13,821	13,821	13,821	13,821	13,821	13,821	13,821	13,821	13,821	165,852
5	Total Fuel Costs	$100,266	$109,418	$121,641	$119,098	$103,339	$114,093	$107,476	$112,253	$128,374	$145,411	$147,083	$129,568	$1,438,019
6	Total MWH Sales	6,152,147	6,008,331	6,560,945	7,022,630	6,808,597	6,233,265	6,145,475	6,095,709	6,969,047	7,546,269	7,935,340	7,585,898	81,063,652
7	Fuel Costs Incurred ¢/kwh	1.6298	1.8211	1.8540	1.6959	1.5178	1.8304	1.7489	1.8415	1.8421	1.9269	1.8535	1.7080	1.7739
8	SC Retail MWH Sales	1,724,933	1,691,527	1,784,147	1,886,680	1,860,198	1,682,976	1,704,313	1,715,560	1,946,496	2,067,447	2,187,506	2,090,087	22,341,870
9	SC Fuel Costs	$28,113	$30,804	$33,078	$31,996	$28,234	$30,805	$29,807	$31,592	$35,856	$39,838	$40,545	$35,699	$396,322
10	(Over)/Under on Exhibit 5													($6,302)
11	SC Fuel Costs													$390,020
12	SC Fuel Cost ¢/kwh													1.7457

McManeus Exhibit 6

McManeus Exhibit 7

DUKE ENERGY CAROLINAS
SOUTH CAROLINA FUEL CLAUSE
2007 ANNUAL FUEL HEARING
SC ENVIRONMENTAL COST (OVER)/UNDER RECOVERY BY CLASS
$000

		Summer 2006 Firm Coincident Peak (CP) KWs	CP %
1	Residential	1,672,099	41.00%
2	General/Lighting	1,155,127	28.32%
3	Industrial	1,251,518	30.68%
4	Total SC	4,078,744	100.00%

	Environmental Costs Incurred	May 2007*	June 2007	Estimate July 2007	Estimate Aug. 2007	Estimate Sept. 2007	Total
5	Reagents Expense	$ 1,151	$ 1,574	$ 2,218	$ 2,240	$ 1,795	$ 8,977
6	Emission Allowance Expense	1,617	1,652	1,304	1,304	1,304	7,181
7	Environmental Costs Recovered in Intersystem Sales	(390)	(1,092)	(1,170)	(1,170)	(1,170)	(4,992)
8	Gain on NOx Sales	(718)	(584)	-	-	(2,000)	(3,302)
9	Net Environmental Costs	$1,661	$1,550	$2,352	$2,373	($71)	$7,864
10	SC % of KWH Sales	26.43%	27.55%	27.46%	27.63%	27.61%	27.31%
11	SC Environmental Costs	$ 439	$ 427	$ 646	$ 656	$ (20)	$ 2,148
12	**SC Environmental Costs Billed [Increment/(Decrement)]**	$ (635)	$ (803)	$ (872)	$ (923)	$ (882)	$ (4,115)
13	**SC Environmental Costs (Over)/Under Recovery**						$ 6,263
	SC Environmental Costs (Over)/Under Recovery Allocated on Firm CP KWs						
14	Residential						$ 2,567
15	General/Lighting						1,774
16	Industrial						1,922
17	Total SC						$ 6,263
	Projected SC MWH Sales from Exhibit 8						
18	Residential						6,579,470
19	General/Lighting						5,743,806
20	Industrial						10,018,595
21	Total SC						22,341,870
	SC Environmental Costs (Over)/Under Recovery ¢/KWH						
22	Residential						**0.0390**
23	General/Lighting						**0.0309**
24	Industrial						**0.0192**

*Effective May 3, 2007, changes in SC law (Section 58-27-865), allow for environmental costs incurred for reducing or treating emissions, to be included in fuel costs used in the fuel factor calculation.

DUKE ENERGY CAROLINAS
SOUTH CAROLINA FUEL CLAUSE
2007 ANNUAL FUEL HEARING
PROJECTED SC ENVIRONMENTAL COST ALLOCATION BY CLASS
$000

		Summer 2006 Firm Coincident Peak (CP) KWs	CP %
1	Residential	1,672,099	41.00%
2	General/Lighting	1,155,127	28.32%
3	Industrial	1,251,518	30.68%
4	Total SC	4,078,744	100.00%

	Environmental Costs	Oct. 2007	Nov. 2007	Dec. 2007	Jan. 2008	Feb. 2008	March 2008	April 2008	May 2008	June 2008	July 2008	Aug. 2008	Sept. 2008	Total
5	Reagents	$ 1,683	$ 1,644	$ 1,720	$ 1,977	$ 1,851	$ 2,051	$ 1,867	$ 2,474	$ 2,611	$ 2,786	$ 2,774	$ 2,343	$ 25,781
6	Emission Allowance Expense	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	15,647
7	Environmental Costs Recovered in Intersystem Sales	(1,170)	(1,170)	(1,170)	(1,170)	(1,170)	(1,170)	(1,170)	(1,170)	(1,170)	(1,170)	(1,170)	(1,170)	(14,040)
8	Gain on NOx Sales	-	-	(2,000)	-	-	-	-	-	(2,000)	-	-	(2,000)	(6,000)
9	Net Environmental Costs	$ 1,817	$ 1,778	$ (146)	$ 2,111	$ 1,985	$ 2,185	$ 2,001	$ 2,608	$ 745	$ 2,920	$ 2,907	$ 477	$ 21,388
10	SC % of KWH Sales	28.04%	28.15%	27.19%	26.87%	27.32%	27.00%	27.73%	28.14%	27.93%	27.40%	27.57%	27.55%	
11	SC Environmental Costs	$ 509	$ 500	$ (40)	$ 567	$ 542	$ 590	$ 555	$ 734	$ 208	$ 800	$ 801	$ 132	$ 5,900
	SC Environmental Costs Allocated on CP KWs													
12	Residential	$ 209	$ 205	$ (16)	$ 232	$ 222	$ 242	$ 228	$ 301	$ 85	$ 328	$ 329	$ 54	$ 2,419
13	General/Lighting	144	142	(11)	161	154	167	157	208	59	227	227	37	1,671
14	Industrial	156	154	(12)	174	166	181	170	225	64	246	246	40	1,810
15	Total SC	$ 509	$ 500	$ (40)	$ 567	$ 542	$ 590	$ 555	$ 734	$ 208	$ 800	$ 801	$ 132	$ 5,900
	SC MWH Sales													
16	Residential	423,564	406,387	558,584	676,281	611,028	510,684	440,895	419,022	550,630	665,845	688,978	627,573	6,579,470
17	General/Lighting	468,053	424,132	438,635	466,999	442,880	418,511	439,498	447,804	519,509	549,409	568,194	560,181	5,743,806
18	Industrial	833,317	861,009	786,928	743,400	806,290	753,780	823,920	848,734	876,357	852,192	930,334	902,333	10,018,595
19	Total SC	1,724,933	1,691,527	1,784,147	1,886,680	1,860,198	1,682,976	1,704,313	1,715,560	1,946,496	2,067,447	2,187,506	2,090,087	22,341,870
	SC Environmental Costs ¢/KWH													
20	Residential													**0.0368**
21	General/Lighting													**0.0291**
22	Industrial													**0.0181**

McManeus Exhibit 8

DUKE ENERGY CAROLINAS
SOUTH CAROLINA FUEL CLAUSE
2007 ANNUAL FUEL HEARING
PROJECTED FUEL FACTOR BY CUSTOMER CLASS

	Summary ¢/KWH	SC Fuel Cost from Exhibit 6	SC Environmental Costs (Over)/Under Recovery from Exhibit 7	SC Environmental Costs from Exhibit 8	Combined Projected Fuel Factor
1	Residential	1.7457	0.0390	0.0368	1.8215
2	General/Lighting	1.7457	0.0309	0.0291	1.8057
3	Industrial	1.7457	0.0192	0.0181	1.7829

McManeus Exhibit 9